COMMUNITY CHOICE AGGREGATION PILOT PROJECT

APPENDIX A:

Community Choice Aggregation Renewable Resource Development Roadmap

Arnold Schwarzenegger
Governor

PIER FINAL PROJECT REPORT

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Prepared By:
Local Government Commission
G. Patrick Stoner
Sacramento, California 95814

Navigant Consulting, Inc.
John Dalessi
Rancho Cordova, California 95670

Contract No. 500-03-004

Gerald Braun, Team Lead
Contract Number: BOA-99-190-S

Prepared For:
Public Interest Energy Research (PIER)
California Energy Commission

Hassan Mohammed
Contract Manager

Kenneth Koyama
Office Manager
Energy Generation Research

Martha Krebs, Ph.D.
PIER Director

Thom Kelly, Ph.D.
Deputy Director
ENERGY RESEARCH & DEVELOPMENT DIVISION

Melissa Jones
Executive Director

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Abstract

This report quantifies the renewable resource requirements of the municipalities that are participating in the Community Choice Aggregation Demonstration project and assesses the costs and availability of renewable resources likely to be available for use in such programs. Assessments are made for renewable resource utilization constrained by transmission limitations in the 2010 and 2017 timeframes for community choice aggregators located within the service territories of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company. The report also provides a discussion of tax advantaged financing options for generation development that are available to municipalities that become community choice aggregators.

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EXECUTIVE SUMMARY

Twelve California municipalities are participating in a demonstration project to evaluate the feasibility of becoming Community Choice Aggregators (CCA), with the goal of significantly exceeding California's renewable energy portfolio standards. Community Choice Aggregation is an option for cities and counties to provide electric service to customers within their boundaries, utilizing the transmission, distribution and billing services of the local distribution utility to deliver electricity procured by the CCA. The purpose of this report is to determine whether there are likely to be sufficient new renewable resources available to meet the objectives of the CCA project participants and to provide a preliminary assessment of renewable resources that may be incorporated in resource plans ultimately developed by the project participants. The report identifies the most likely resource types and locations for development based on review of publicly available data regarding resource potential, cost and transmission capabilities.

Seven of the project participants are located within the service territory of Pacific Gas & Electric (PG&E); three are within Southern California Electric's (SCE) service territory; and two are within San Diego Gas & Electric's (SDG&E) service territory. Initial feasibility studies conducted for the participants found that it would be economically feasible for the participants to significantly increase utilization of renewable energy by forming CCA programs. Access to renewable facilities owned by public agencies, which may include the CCA itself, was found to be a critical factor in being able to achieve this objective. The feasibility study examined the costs of commercially available renewable energy resources, but it did not attempt to identify where such resources would likely be located or whether transmission constraints would limit the participants' ability to reach the renewable energy utilization objectives. These latter considerations are the focus of this study.

Following review of the initial feasibility studies, four of the original seven project participants in the PG&E service area have decided to continue to the next stage of program development planning. The participants in SCE and SDG&E service territories have not yet decided whether to continue their program development efforts. For purposes of this report, we assume that two of the three participants in SCE's service territory and both of the participants in SDG&E's service territory will continue their evaluation of forming CCA programs.

The primary focus of this report is to determine the likely areas for resource development that could be utilized to meet the renewable procurement targets preliminarily established by the project participants. The assessment is largely based on review of existing studies covering resource potential, cost, and transmission availability and review of renewable resource plans recently prepared by PG&E, SCE and SDG&E. The 2010 time period is of particular concern for CCA renewable resource planning because CCAs must meet 20% of their resource procurement from renewable resources by this time, yet this is before anticipated completion of several major transmission projects that are currently being planned to provide access to the most resource-rich areas in California.

Project participants are still in the process of investigating forming CCA programs. The program details have not yet been developed and many decisions regarding timing for program implementation and resource planning are yet to be made. For purposes of this report, it is assumed that four CCA programs would begin in 2008, and their renewable resource plans would be designed to achieve the renewable energy objectives established by the project participants during the initial feasibility studies. These renewable objectives range from 20% to 51% by 2017. The Project Participants' renewable energy targets are shown in Table 1.1 below:

Table 1.1: Renewable Energy Targets for Project Participants (Mwh per Year)

Region	Renewable Targets By 2010	Renewable Targets By 2017
PG&E Area	858,010	2,388,438
SCE Area	389,747	460,132
SDG&E Area	671,731	774,546

Transmission is generally a constraining factor in determining suitable sources for supplying renewable energy to load centers in California, and project participants should look first to the resources that are available within the service area of the relevant distribution utility when conducting their renewable resource planning activities. In order to be considered for use by 2010 in this report, resources must be economically developable, and their development must not pose transmission system impacts that would require major transmission system network upgrades. Minor transmission system upgrades and interconnection facilities can be accomplished by 2010, but major transmission system upgrades would already have to be well into the planning stages for completion by that time. Based on these criteria, the estimates of renewable resources that could by developed by 2010 for CCA programs in each the three IOU service areas are shown in Table 1.2.

Table 1.2: Resources Identified for Potential CCA Development By 2010, Considering Existing and Planned Network Transmission System Capacity (MWh)

Resource Type	PG&E Area	SCE Area	SDG&E Area[1]
Geothermal	1,576,800	0	5,085,180
Wind	525,236	4,780,800	394,200
Biomass	525,000	1,094,562	156,366
Total	2,627,036	5,875,362	5,635,746

The estimates indicate that project participants in the PG&E and SCE service areas should be able to meet their 2010 renewable requirements from resources internal to the service area. Project participants in the SDG&E service area will likely need to rely on imports of renewable energy from the Imperial Valley or possibly utilization of unbundled renewable energy certificates (if permitted by the CPUC) to meet their 2010 requirements. Project participants should also be cognizant that competition for renewable resources from other load serving entities, particularly the local distribution

[1] The geothermal resources are located in Imperial Valley and will be deliverable to San Diego area loads following completion of Phase 1 of San Diego Gas & Electric's proposed Sunrise Powerlink in 2010. Wind resources in Eastern San Diego County are planned to be connected via tap lines to the Sunrise Powerlink.

utilities (PG&E, SCE, and SDG&E) seeking to meet their own renewable energy requirements, could hinder CCA renewable procurement efforts.

This report utilizes data from several renewable energy studies, utility resource plans and transmission studies to help guide the project participants' renewable resource planning. The focus is on development of new resources. It bears noting that project participants may also be able to meet a portion of their renewable energy demands with purchases from existing resources, particularly from "qualifying facilities" that are under contract with the local distribution utility as these contracts expire over the next several years.

This report shows that project participants should focus their renewable resource planning efforts for new resources on the following areas:

Project Participants in the PG&E Service Area

Near Term

- Geothermal in Lake and Sonoma Counties
- Expansion and re-powering of wind resources in Alameda County
- Local biomass projects

Longer Term

- Wind resources in Solano County
- Wind imports from the Tehachapi Area
- Wind imports from the Pacific Northwest
- Geothermal imports from Nevada
- Geothermal imports from the Imperial Valley
- Solar CSP imports from Southern California (Riverside and San Bernardino Counties)

Project Participants in the SCE Service Area

Near Term

- Wind resources in the Tehachapi area (Phases 1 and 2)
- Re-powered wind in Riverside and San Bernardino Counties
- Local biomass projects

Longer Term

- Wind resources in the Tehachapi area (Phase 3) and Riverside County
- Solar CSP in Riverside and San Bernardino Counties
- Geothermal imports from the Imperial Valley
- Geothermal imports from Nevada

Project Participants in the SDG&E Area

Near Term

- Geothermal imports from the Imperial Valley
- Wind resources in Eastern San Diego County
- Local biomass projects

Longer Term

- Wind imports from the Tehachapi Area and Riverside County
- Solar CSP in San Diego
- Solar CSP imports from Imperial, Riverside and San Bernardino Counties

Project participants may use tax-exempt financing to reduce the cost of procuring renewable energy for their CCA programs. Such financing can provide cost reductions approaching 20% relative to purchases from privately owned renewable projects. Revenue bonds are an appropriate financing mechanism available to CCAs. Issuance of revenue bonds will require a demonstration that the CCA program has a broad and stable base of customers that will provide revenues for repayment of the bonds; that it has an enforceable means of recovering potentially stranded costs from customers that leave the program; or that the CCA has another credible means of repaying the bonds. Electricity and gas prepayments are other available financing mechanisms that can lower renewable procurement costs for CCAs. As CCA programs are developed, planners should work closely with the municipalities' bankers, bond and tax counsel to ensure the program implementation plan provides appropriate credit for future debt issuances.

1. INTRODUCTION

Twelve California municipalities are participating in a demonstration project to evaluate the feasibility of becoming Community Choice Aggregators (CCA), with the goal of significantly exceeding California's renewable energy portfolio standards. Community Choice Aggregation is an option for cities and counties to provide electric service to customers within their boundaries, utilizing the transmission, distribution and billing services of the local distribution utility to deliver electricity procured by the CCA. The purpose of this report is to determine whether there are likely to be sufficient new renewable resources available to meet the objectives of the CCA project participants and to provide a preliminary assessment of renewable resources that may be incorporated in resource plans ultimately developed by the project participants. The report identifies the most likely resource types and locations for development based on review of publicly available data regarding resource potential, cost and transmission capabilities.

The next stage of CCA program development includes formulating more detailed long term resource plans. This report provides a roadmap for the participants' renewable resource planning efforts by examining:

1. Annual renewable energy requirements of the project participants deemed likely to implement CCA programs by geographic region;
2. Cost and availability of renewable resources likely to be commercially developable in the next several years for each region;
3. Availability of existing transmission capacity to integrate the identified renewable resources; and
4. Use of and restrictions for tax-exempt financing for developing renewable facilities used in supplying the CCA programs.

2. Renewable Energy Requirements for Project Participants

2.1 Basic RPS Requirements Applicable to CCAs

CCAs are required by law and the related CPUC regulations to procure a minimum percentage of their retail electricity sales from qualified renewable energy resources. Under the California renewable portfolio standards (RPS) program and policies established in the state's Energy Action Plan, each CCA must generally increase its percentage utilization of renewable energy by no less than 1% per year and achieve a minimum of 20% by 2010. For purposes of determining CCA renewable energy requirements, we assume the same standards for RPS compliance applicable to the major investor owned utilities (IOUs) will also apply to CCAs. The Commission has ruled that CCAs must comply with five fundamental aspects of the RPS program: 1) meeting the 20% requirement by 2010; 2) increasing their renewable sales by at least 1% per year; 3) reporting their progress to the CPUC; 4) utilizing flexible compliance mechanisms; and 5) being subject to penalties and penalty processes. Additional specifics of how CCAs, non-regulated energy service providers (ESPs) and multi-jurisdictional utilities are to comply with the RPS and how their compliance may be different in some respects than the rules that are applicable to the IOUs are being addressed in the ongoing CPUC proceeding, R.06-02-012. The rules ultimately adopted for CCAs may provide greater flexibility than assumed in this report, for instance, by allowing use of short-term contracting or unbundled renewable energy certificates for RPS compliance. The project participants' renewable resource plans should incorporate any changes in these assumptions that result from the CPUC's rulemaking process.

2.2 Commission RPS Compliance Rules

CPUC Decision No. 04-06-014 clarifies the methodology for calculating the annual renewable energy requirements needed to comply with the RPS. In that decision, the CPUC defines two related terms to measure a load serving entity's progress toward meeting its RPS obligations. The "Annual Procurement Target" (APT) is the total amount of renewable energy needed to meet the requirement to increase renewable procurement by at least 1% of retail sales per year, subject to Commission rules for flexible compliance. It is the sum of the "Baseline", representing renewable generation needed to continue to satisfy obligations under the RPS targets of previous years, and the "Incremental Procurement Target", which is at least 1% of the previous year's total retail electrical sales.

The Commission's flexible compliance rules articulated in D.03-06-071 allow a load serving entity to defer up to 25% of the APT without explanation, as long as the shortfall is made up within three years. Shortfalls greater than 25% of APT will be permitted upon demonstration of one or more of the following: 1) insufficient response to a request-for-offers; 2) contracts in hand that will make up the deficit in future years; 3) inadequate public goods funds to cover above market renewable contract costs; and 4) seller nonperformance. Flexible compliance does not currently extend the 20% by 2010 requirement. Noncompliance will result in penalties of 5 cents per kWh, capped at $25 million per year.

Because CCAs will have no baseline of renewable energy procurement and no prior retail electrical sales, their first year APT calculated as described above would be zero. In 2009, the expected second year of the program, a CCA must procure at least 1% of its 2008 retail sales from renewable resources, and in 2010, a CCA must meet the full 20% renewable standard. Notwithstanding the minimum RPS requirements, the CCAs' renewable procurement goals preliminarily established by the project participants will significantly exceed the RPS requirements, as shown in Table 2.3.

2.3 RPS Requirements for CCA Project Participants

The renewable energy needed for project participants' compliance with the RPS is shown in Table 2.1. These requirements are calculated as if the CCA served all existing bundled service customers within their jurisdictional boundaries beginning in 2008. Actual RPS requirements will be determined considering the CCA's annual retail sales, which may be significantly reduced from these figures due to customers exercising their rights to opt out of the programs. A CCA that implements its program in phases may also have fewer retail sales than shown in Table 2.1 in any particular year subject to the phase-in. An objective of this report is to provide a preliminary assessment of whether resource availability or transmission constraints are likely to constrain meeting the renewable energy goals of program participants. Therefore, we take the total potential retail sales of the CCA participants as a starting point of this assessment.

Table 2.1: Annual Procurement Targets to Meet RPS For All Project Participants(MWh Per Year)

Participant	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Berkeley	-	5,386	110,249	111,544	112,860	114,195	115,551	116,928	118,325	119,744
Emeryville	-	2,119	43,646	44,296	44,956	45,626	46,306	46,996	47,696	48,407
Marin County	-	14,202	292,565	296,929	301,358	305,853	310,416	315,048	319,749	324,520
Oakland	-	19,981	411,551	417,650	423,840	430,123	436,501	442,974	449,544	456,213
Pleasanton	-	7,271	157,264	163,540	170,066	176,853	183,912	191,253	198,888	206,828
Richmond	-	5,859	120,678	122,471	124,291	126,138	128,013	129,916	131,847	133,808
Vallejo	-	4,622	95,197	96,607	98,038	99,490	100,964	102,460	103,979	105,520
Subtotal PG&E Service Area	-	59,439	1,231,150	1,253,036	1,275,408	1,298,279	1,321,662	1,345,574	1,370,028	1,395,040
Beverly Hills	-	5,879	123,300	126,259	129,289	132,392	135,569	138,823	142,155	145,566
LA County	-	44,369	930,494	952,826	975,693	999,110	1,023,089	1,047,643	1,072,786	1,098,533
West Hollywood	-	3,413	71,574	73,292	75,051	76,852	78,696	80,585	82,519	84,499
Subtotal SCE Service Area	-	53,662	1,125,367	1,152,376	1,180,033	1,208,354	1,237,354	1,267,051	1,297,460	1,328,599
San Marcos	-	4,243	88,894	90,980	93,116	95,302	97,539	99,829	101,825	103,862
San Diego County	-	27,745	582,837	595,549	607,459	619,608	632,001	644,641	657,533	670,684
Subtotal SDG&E Service Area	-	31,988	671,731	686,529	700,575	714,910	729,540	744,469	759,359	774,546
Total	-	145,089	3,028,248	3,091,941	3,156,016	3,221,543	3,288,556	3,357,094	3,426,847	3,498,185

Recognizing not all of the original project participants are likely to continue their investigation of forming CCA programs, we can narrow the focus to those participants that are continuing to explore forming CCA programs or that are reasonably likely to continue their CCA development efforts. These participants have been grouped into regional entities that may together form CCA programs. The annual RPS requirements for the regional consortia are summarized in Table 2.2.

Table 2.2: Annual RPS Requirements for Potential CCA Consortia (MWh Per Year)

CCA Group	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
East Bay	-	27,486	565,445	573,490	581,656	589,944	598,357	606,897	615,566	624,364
Marin	-	14,202	292,565	296,929	301,358	305,853	310,416	315,048	319,749	324,520
Westside LA	-	9,292	194,873	199,550	204,340	209,244	214,266	219,408	224,674	230,066
San Diego Area	-	31,988	671,731	686,529	700,575	714,910	729,540	744,469	759,359	774,546
Total	-	82,968	1,724,614	1,756,498	1,787,928	1,819,952	1,852,579	1,885,822	1,919,347	1,953,497

2.4 PROJECT PARTICIPANTS' RENEWABLE ENERGY GOALS IN EXCESS OF THE RPS

Whereas the RPS rules establish minimum renewable procurement requirements for CCAs, the participants in PG&E's service territory have preliminarily established higher renewable goals than required by the RPS program. For planning and evaluation purposes the East Bay cities have established a goal of achieving a 50% renewable target by 2017, and the group in Marin County has established a goal of sourcing the majority of its retail sales from renewable resources (51% minimum). In SCE's territory, the Westside cities have expressed a desire to achieve a 40% renewable target by 2010. The participants in the San Diego area have not established renewable goals in excess of the RPS at this time, and for purposes of this study are assumed to match the RPS standards applicable to SDG&E.

Table 2.3 shows the annual renewable energy needed to meet the project participants' goals of exceeding the RPS. Note that if these project participants are successful in forming CCA programs and achieving their targets, the amount of renewable energy utilized would surpass the RPS by over a million MWh in 2008 and nearly 1.7 million MWh in 2017.

Table 2.3: Annual Renewable Energy Utilization Need to Meet CCA Project Participants' Renewable Energy Goals (MWh Per Year)

CCA Group	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
East Bay	466,568	515,357	565,445	696,381	830,937	969,194	1,111,235	1,257,144	1,407,007	1,560,911
Marin	241,071	266,466	292,565	360,556	430,511	502,474	576,488	652,599	730,855	827,527
Westside LA	371,691	380,612	389,747	399,101	408,679	418,487	428,531	438,816	449,347	460,132
San Diego Area	-	31,988	671,731	686,529	700,575	714,910	729,540	744,469	759,359	774,546
Total	1,079,330	1,194,423	1,919,488	2,142,567	2,370,702	2,605,065	2,845,794	3,093,029	3,346,568	3,623,116
RPS Minimum	-	82,968	1,724,614	1,756,498	1,787,928	1,819,952	1,852,579	1,885,822	1,919,347	1,953,497
In Excess of RPS	1,079,330	1,111,456	194,873	386,069	582,774	785,114	993,215	1,207,206	1,427,221	1,669,619

2.5 RPS REQUIREMENTS OF THE MAJOR INVESTOR OWNED UTILITIES

Of course, CCAs will not be alone in attempting to procure significant renewable energy supplies during the next decade, as the RPS applies to all load serving entities in California, with the three major investor owned utilities being the predominant players.[2] The three IOUs are pursuing contracts with renewable generators to ramp up to the 20% renewable target by 2010. Additional procurement will be needed thereafter to maintain the target as load grows. From a CCA's perspective, IOU renewable procurement represents competition for limited resources in the short-run but a means to expand supplies of renewable energy available to CCAs in the long term because the IOUs will need to build new transmission to meet their RPS obligations. Table 2.4 shows the incremental renewable procurement required by the three major investor owned utilities on an annual basis to meet the RPS applicable in 2010 and 2017.

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[2] In addition current law allows publicly owned (municipal) utilities to establish their own renewable procurement standards, consistent with the Renewable Portfolio Standards program objectives, and Energy Service Providers are subject to Renewable Portfolio Standards requirements.

Table 2.4: RPS requirements of the Major Investor Owned Utilities (MWh)

IOU	Incremental RE Procurement By 2010[3]	Incremental RE Procurement By 2017[4]
PG&E	6,570,000	8,220,000
SCE	3,059,000	4,788,000
SDG&E	1,968,000	2,275,000

Combined, the IOUs will need to procure nearly 12 million MWh of renewable energy on an annual basis to meet the 2010 target. These resources are in addition to the 1.9 million needed by the project participants to meet their renewable energy goals.

3 Based on data provided by the California Energy Commission, CEC-400-2005-034-SD, with Navigant Consulting Inc. adjustments for retail sales that would transfer to the Community Choice Aggregators' portfolios.

4 2017 Renewable Portfolio Standard requirement based on assumed load growth of 1.5% per year from 2010 through 2017.

3. Overview of Renewable Energy Potential

This section provides a description of eligibility rules for complying with the state's RPS program and then summarizes the most recent studies regarding renewable resource potential.

3.1 Resource Eligibility

To qualify as eligible for California's RPS, a generation facility must use one or more of the following renewable resources or fuels:

- Biomass
- Biodiesel
- Fuel cells using renewable fuels
- Digester gas
- Geothermal
- Landfill gas
- Municipal solid waste
- Ocean wave, ocean thermal, and tidal current
- Photovoltaic
- Small hydroelectric (30 megawatts or less)
- Solar thermal
- Wind

Certain restrictions apply for eligibility for the RPS and subsidies from public goods charges (Supplemental Energy Payments). Resource or fuel-specific eligibility requirements are summarized in the Appendix, Table A.7.

3.2 Renewable Resource Potential

California's vast renewable resource potential is well documented in a series of recent studies commissioned by the California Energy Commission and the California Public Utilities Commission (CPUC). The two primary data sources for the resource availability and cost estimates used in this report are: 1) the series of renewable energy studies used in developing the Energy Commission's 2005 Integrated Energy Policy Report (IEPR), known as the Strategic Value Analysis studies; and 2) a study commissioned by the California Public Utilities Commission that evaluated the feasibility and impact of achieving a 33% renewable energy target by 2020. Although not used in this report, an earlier Energy Commission study known as the Renewable Resources Development Report also found that vast quantities of renewable energy potential exist in California and neighboring states.[5] The two more recent studies are summarized below.

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[5] California Energy Commission, Renewable Resources Development Report, November 7, 2003, 500-03-080FD

3.2.1 ENERGY COMMISSION 2005 IEPR STRATEGIC VALUE ANALYSIS STUDIES

In support of the 2005 Integrated Energy Policy Report, the Energy Commission conducted a series of studies to identify renewable resource potential within California, including an assessment of the impacts on the transmission system of developing resources at various locations on the grid. The Strategic Value Analysis studies screened potential renewable energy potential for both economic and transmission limitations, concluding the state could meet 85% of the 20% RPS goals in 2010 from in-state renewable resources with little increase in new transmission lines. The remaining 15% can be developed from out-of-state resources and/ or from in-state resources that will need new transmission capacity. It should be noted that the resources identified in the SVA study were selected primarily to test the methodology being proposed in the study for planning renewable resource development in a manner that accounts for transmission grid impacts. The study does not contain an exhaustive inventory of renewable energy potential. For example, the report evaluated six high wind sites and suggests that many other high wind sites should be evaluated in future studies. The resources identified in the SVA study are those that: 1) were initially selected for study to test the methodology; 2) were found to have positive impact on the transmission system if developed; and 3) whose estimated levelized costs are at or below the market price benchmark. The latter screen filters out any projects that could be developed at prices reflecting a premium to prevailing wholesale market prices and that may be offset by the renewable subsidies available through the public goods surcharge on utility bills. For these reasons, the SVA study results should not be interpreted as an absolute ceiling on renewable resource development potential.

Table 3.1 summarizes the findings of the SVA studies. The resources shown are those that would provide benefits to the transmission system if developed, according to the methodology used in the study, and that also have levelized costs at less than 6.05 cents per kWh in 2010 or 9.15 cents per kWh in 2017. The higher MWs shown for 2017 relative to 2010 are due to differences in the market price benchmarks and levelized costs used in those years; i.e., the additional capacity in 2017 is due to economic factors, not assumptions regarding physical availability of resources or new transmission capacity.

Table 3.1: Renewable Resources Identified by the Energy Commission's Strategic Value Analysis

Service Territory	Technology	MW By 2010	MW By 2017
PG&E	Biomass Forestry	0	382
	CSP Solar	0	0
	Geothermal	43	468
	High Wind	407	407
	Low Wind	0	281
Subtotal: PG&E	**All**	**450**	**1,538**
SCE	CSP Solar	1,046	1,046
	High Wind	2,784	2,784
Subtotal: SCE	**All**	**3,830**	**3,830**

Service Territory	Technology	MW By 2010	MW By 2017
SDG&E	CSP Solar	35	35
	High Wind	150	150
Subtotal: SDG&E	**All**	**185**	**185**
Imperial	CSP Solar	66	66
	Geothermal	1,596	1,903
Subtotal: Imperial	**All**	**1,662**	**1,969**
Pacificorp	**Geothermal**	**175**	**248**
Not Attributed	Dairy Manure	38	38
	Landfill Gas	318	318
	Wastewater Treatment	59	59
	Urban Fuel	0	497
	Residential Solar	500	500
Subtotal: Not Attributed	**All**	**915**	**1,412**
Statewide Total	**All**	**7,217**	**9,182**

Source: *Strategic Value Analysis for Integrating Renewable Energy Technologies in Meeting Target Renewable Penetration; In Support of the 2005 Integrated Energy Policy Report; Davis Power Consultants, June 2005. Costs are in 2005 dollars.*

3.2.2 CPUC Report: Achieving a 33% Renewable Energy Target

A 2005 study commissioned by the CPUC and conducted by the Center For Resource Solutions (CPUC Study) found that the state could achieve a 33% renewable resource mix by 2020 with minimal rate impacts in the short term and substantial ratepayer savings over the long term. Transmission costs for facilities needed to interconnect new renewable resources are included in the savings estimates. The CPUC Study provides a comprehensive analysis of available renewable resources within California and neighboring states, drawing upon several other studies to supplement the Energy Commission's SVA analysis.

The study found sufficient resources are available statewide to meet a 33% renewable energy target by 2020, as summarized in the table below:

Table 3.2: Comparison of Resource Needs and Developable Resources By 2017

Resource	Projected Resource Need	Identified Resource Available
Wind	7,600 MW	11,800 MW High Speed Sites 19,000 MW Low Speed Sites
Geothermal	1,800 MW	3,400 MW
Biomass	600 MW	1,500 MW
Solar	2700 MW	14,000 MW

Source: Tehachapi Study Group; Imperial Valley Study Group; CEC SVA and Hetchy-PIER

Source*: Achieving A 33% Renewable Energy Target; J.Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005. Costs are in nominal dollars.*

The focus of the CPUC Study is whether it would be feasible for California to achieve a 33% renewable energy target by 2020. The 2020 timeframe for evaluation allows time for expansion of the transmission system to accommodate interconnection of renewable resources in high potential areas such as the Tehachapi wind and Imperial Valley geothermal resource areas, where insufficient transmission infrastructure presently exists to fully utilize the resource potential. These estimates can inform long-term resource planning with the understanding that such plans will be dependent upon new transmission infrastructure projects being undertaken by the IOUs or other transmission owners.

In addition to these existing studies, the Energy Commission continues to study the effects of integrating large amounts of renewable energy on the electric grid, including analysis of the effects of intermittent resources. The Intermittency Analysis Project is studying the impacts of increasing renewable energy penetration on transmission system reliability and on transmission operations. A final report is scheduled to be available in April 2007.

3.2.3 NEW SOLAR RESOURCES

The CPUC Study projected 400 MW of central station and distributed solar resources will be developed by 2010, split evenly between CSP in Southern California and PV distributed throughout the state.[6] Total technical potential for PV installed on residential and commercial rooftops is estimated by the Energy Commission at 38,000 MW and 37,000 MW, respectively.

[6] Source: *Achieving A 33% Renewable Energy Target*; J. Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005.

FIGURE 3.1: ENERGY COMMISSION ESTIMATES OF PV POTENTIAL

Figure 4: Residential PV Potential

Figure 5: Commercial Building PV

Source: *California Solar Resources, In Support of the 2005 Integrated Energy Policy Report, Energy Commission Draft Staff Paper, CEC-500-2005-072-D*

The relatively high costs of PV systems means that little of this potential is likely to be realized absent significant incentives and outreach programs administered by load serving entities. On January 12, 2006, the California Public Utilities Commission approved the California Solar Initiative which provides $2.8 billion in incentives towards solar development over 11 years. The goal is to achieve 3,000 MW of new solar development statewide by 2017. Funding for the program will come from public goods surcharges paid by all ratepayers within the service territories of PG&E, SCE, SDG&E and SoCal Gas. It is not yet known how distributed solar will be accounted for in meeting a load serving entity's renewable portfolio standards obligations, particularly in situations such as CCA or Direct Access where the energy supplier and the distribution utility are different entities. The question arises whether the behind-the-meter solar power can be counted toward the renewable portfolio standard and which entity should be entitled to claim the renewable energy credit. Issues related to net energy metering and measurement of distributed energy systems are being addressed by the CPUC in R.04-03-017.

3.3 RESOURCE COSTS

There is a wide distribution of expected costs for renewable energy, depending upon resource technology, location, transmission impacts, ownership structure, tax credits and other incentives.

3.3.1 PRIVATE DEVELOPERS' COSTS

The CPUC Study provides the most recent range of costs for privately developed projects for each of the commercially available renewable energy technologies. The estimated levelized costs include operating and maintenance costs, financing costs, profits or return on equity and taxes. One of the largest uncertainties regarding renewable energy costs is whether federal production tax credits (PTC) will continue to be available to renewable developers or whether the PTC will be allowed to expire in 2007. The 2005 Energy Policy Act extended the PTC through 2007, at which point it will expire unless reauthorized by Congress. Table 3.3 shows levelized costs without the tax credits, and Table 3.4 shows levelized costs with the tax credits, both taken from the CPUC Study. For reference, NCI estimates the projected forward cost of base load, non-renewable energy will range from $60 to $80 per MWh through 2017.

Table 3.3: Levelized Costs for Renewable Energy Technologies, Excluding Use of Production Tax Credits or Investment Tax Credits

Technology	"Expected" LCOE $/MWhr	Low LCOE $/MWhr	High LCOE $/MWhr
Wind	66	58	83
Geothermal	86	68	100
Biomass – Dairy and LFG	58	48	78
Biomass – Ag Residues	88	78	108
Concentrating Solar	120	100	160
PV	200	120	300

PTC = Production Tax Credit, ITC = Investment Tax Credit.
Source: Strategic Value Analysis and 2005 IEPR Documentation with adjustments by CRS

Table 3.4: Levelized Costs for Renewable Energy Technologies, Including Use of Production Tax Credits For Wind, Biomass and Geothermal and 30% Investment Tax Credits for Solar

Technology	"Expected" LCOE $/MWhr	Low LCOE $/MWhr	High LCOE $/MWhr
Wind	48	40	65
Geothermal	68	50	82
Biomass – Dairy and LFG	40	30	60
Biomass – Ag Residues	70	60	90
Concentrating Solar	90	80	120
PV	160	90	240

Source: Strategic Value Analysis and 2005 IEPR Documentation with adjustments by CRS

Source: *Achieving A 33% Renewable Energy Target; J.Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005. Costs are in nominal dollars.*

The impact of the PTC is to reduce levelized costs by approximately 1.8 cents per kWh. To the extent that prices reflect developers' costs, the availability of the PTC will be a significant uncertainty for purchasers of renewable energy from newly developed projects. CCAs could alternatively elect to own the project or participate in a project owned by another public agency, rather than purchasing energy from private developers. The economics of publicly owned renewable projects are discussed below.

3.3.2 COST OF PUBLICLY FINANCED RENEWABLE RESOURCES

CCAs can buy renewable energy from third parties or elect to own their own resources and must weigh the costs and benefits of the "build vs. buy" option in formulating their procurement strategies. In the absence of the PTC, or if the CCA can take advantage of the publicly owned equivalent credit (Federal Renewable Energy Production Incentive or "REPI"), a CCA's ownership costs will generally be lower than a private developer's costs because of the CCA's non-profit status. Public ownership, either through direct ownership by the CCA or through participation in projects financed by another public agency, will generally yield lower overall costs because of the ability to finance facilities with tax-exempt debt and the avoidance of profit margins and taxes that would otherwise be reflected in prices paid to a private entity. On the other hand, private developers can take advantage of a 5-year accelerated depreciation schedule for income tax purposes and potentially may be able to take advantage of the PTC. The REPI has been subject to annual Congressional appropriations and viewed as less certain than the PTC. Previous studies have shown that on a levelized cost basis, public ownership of renewable energy resources yields lower costs if the private owner cannot take advantage of the PTC. The reverse is true if the PTC is utilized and the publicly owned utility cannot utilize the REPI.[7]

Table 3.5 shows current NCI estimates of levelized costs of the two most prominent renewable energy technologies, wind and geothermal, under the assumption that the facility is owned by: 1) private entities taking advantage of the PTC; 2) private entities without access to the PTC; and 3) publicly owned utilities or CCAs with and without the REPI.

Table 3.5: Levelized Cost Comparison of Public and Private Renewable Facilities

Levelized Cost Comparison Of Renewable Energy Facilities
Private Vs. Publicly Financed Resources

Technology	Private W/PTC	Private W/O PTC	Public W/REPI	Public W/O REPI
Wind	$53	$66	$42	$54
Geothermal	$66	$85	$57	$70

Source: *Assumptions and calculation of levelized costs are contained in the Appendix, Table A.8.*

[7] For a good discussion, see *Revisiting the "Buy Versus Build" Decision for Publicly Owned Utilities in California Considering Wind and Geothermal Resources*, Ernest Orlando Lawrence Berkeley National Laboratory, October 2001.

As shown in Table 3.5 above, CCA ownership of renewable energy facilities would be nearly 20% cheaper than purchases from privately owned facilities if the PTC is allowed to expire as scheduled or if the publicly owned facility receives the REPI. Public ownership may also be the lower cost option under the worst case where no REPI is available and the PTC is extended by Congress beyond the current expiration date of 2007 if demand for renewable energy drives up investment returns for private developers. As in any market, prices bid by suppliers are not necessarily similar to levelized project costs. Levelized costs would be a reasonable proxy for market prices if the market for renewable energy was at rough equilibrium; i.e., it was neither a seller's nor a buyer's market. The current market appears tilted in favor of sellers due to strong demand for renewable energy created by the accelerated RPS requirements and relatively high prices for non-renewable energy. If that is the case, the actual prices bid by renewable developers during the next few years will likely be above estimated equilibrium costs. For a CCA, the cost of public ownership should be viewed as a cap on what it is willing to pay for energy from a power purchase agreement with renewable energy developers. The option to own the resource gives a CCA the advantage of capping its exposure to future renewable energy cost increases that might occur if the renewable development tax incentives are allowed to expire or if renewable developers are able to exercise market power by charging price premiums for available projects. The final build/ buy decision for a CCA needs to be made based on specific market data obtained through negotiations with energy suppliers or developers.

3.4 CONCLUSION

The current body of research indicates there is plentiful renewable resource potential for meeting California's renewable energy goals and that many of these renewable resources are cost-effective relative to generation fueled by natural gas. While renewable resource potential within the state is vast, the lack of existing transmission facilities necessary to interconnect the renewable resource areas – which are typically far from population centers – and the lack of sufficient transfer capability on key transmission paths to enable delivery to load centers may be a limiting factor in acquiring renewable energy to meet the project participants' resource planning goals. The long lead time needed to build significant new transmission projects (typically 4 to 7 years) limits the pace at which the State's renewable resource base can be expanded.

State policy makers have for several years recognized the lack of adequate transmission infrastructure to support development of the most promising renewable resource areas, and several major transmission investments are underway or being planned to accommodate the anticipated renewable resource development. The CPUC Study provides ample evidence that the project participants will be able to meet their long term renewable energy targets as long as the IOUs complete the identified transmission projects needed for compliance with their own RPS obligations. These initiatives will expand the choices available to all load serving entities, including CCAs, for acquiring renewable energy in the 2012 to 2017 time horizon. The more challenging prospect will be meeting the CCAs' renewable energy goals in the 2008 to 2011 time horizon. For the near term, when transmission is the predominant constraining factor, the Energy Commission SVA Study's estimates of developable resources can be used along with transmission data provided by the IOUs to form the best estimates of what could realistically be available for use by project participants prior to the time the IOUs' major renewable-related transmission projects can be completed. The results of this approach are presented in Section 4 for potential CCAs in each of the three utility service territories.

4 IMPLICATIONS FOR PROJECT PARTICIPANTS' RENEWABLE PROCUREMENT EFFORTS

This section synthesizes data from a variety of sources on resource availability, costs, and transmission limitations to identify specific resource types and geographic locations for consideration by project participants as they formulate their renewable resource plans.

4.1 LOCATIONAL PLANNING CONSIDERATIONS

Current transmission constraints generally limit the quantity of renewable energy that can be delivered to loads within a CCA's jurisdiction from resources outside of the larger host utility (PG&E, SCE, SDG&E) service territory. Transmission transfer capability for energy imports from other utility service territories or from neighboring states is available during certain times of the year but is not sufficient to ensure delivery of electricity to loads during all times. Electricity transmitted from points outside of the utility's service territory is also subject to potential charges for use of congested transmission lines. Congestion charges will become a more significant economic factor as the California Independent System Operator (CAISO) transitions from the current zonal congestion pricing model to a nodal model as it implements its Market Redesign and Technology Update (MRTU).[8] Ideally, considering transmission issues, the energy source would be located near the load center. The next best alternative would be for the resource to be located within or delivered to the host utility service area. From a buyers' perspective, the location of the resource is less important than the point of delivery specified in the power purchase agreement. Supply offers could be considered for renewable energy projects located virtually anywhere in the Western Interconnection as long as the electricity is deliverable to the CAISO control area, as required to meet the Commission's RPS rules. The costs of transmission access and the risk of transmission congestion costs would need to be considered in the bid evaluation process if the delivery point is outside of the applicable load zone defined by the CAISO, currently expected to correspond to the host utility service area.

Likely renewable resource types and locations are identified in this report for resource planning purposes, considering the available data on resource potential, transmission limitations and utility transmission expansion plans. The purpose of identifying likely resource areas is not to prejudge the outcome of future renewable procurement efforts but rather to ascertain whether the project participants' renewable energy goals are realistically attainable based on the best information currently available. The project participants electing to follow through with forming CCA programs will ultimately request proposals from renewable developers or other energy suppliers, and responses to the solicitations will determine the specific resources to be utilized in their programs.

4.2 UTILITY TRANSMISSION COST RANKING REPORTS

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[8] Under the current zonal model, there are potential congestion costs for transferring electricity between any of the three zones within California (NP15, ZP26 and SP15). The nodal model will expand the number of congestion pricing points, creating thousands of locational pricing nodes.

The pool of developable renewable resources is limited in the near term by how much of the potential capacity the existing transmission system can accommodate absent significant upgrades. Preliminary information is available from the three major investor owned utilities that enables identification of areas where transmission appears adequate for integrating new resource development and for estimating costs of expansion where the system is constrained. In compliance with CPUC directives, PG&E, SCE and SDG&E each prepares an annual Transmission Ranking Cost Report (TRCR) used to estimate the costs of upgrades to its transmission system needed to accommodate interconnection and delivery of power from potential renewable energy development.

The primary purpose of the transmission cost estimates is to be used in ranking bids received from developers in response to the utilities' renewable energy solicitations. Various levels of transmission capacity and upgrade costs are estimated for regional transmission "clusters" where significant renewable energy potential exists. The cost estimates are high level approximations, and more detailed studies would be performed to estimate system impacts of specific proposed generation projects. Despite the limitations in the data, they can be used to provide indicative estimates of locations where renewable resources could be added without imposing significant transmission impacts that would require costly and time consuming transmission upgrades.

4.3 CCAs Located Within the PG&E Service Territory

In the near term, project participants will likely utilize renewable capacity developed within the PG&E service territory, primarily geothermal and wind power. These types of resources are relatively low cost and provide "utility scale" capacity needed to meet the project participants' renewable requirements. Based on resource potential and existing transmission availability, the most likely sources of renewable energy for these project participants in the near term are focused in three areas:

- Geothermal resources in the Geysers areas comprising portions of Lake, Sonoma, and Napa Counties;
- Expansion and re-powering of wind projects in the Altamont pass; and
- Local biomass projects.

Studies summarized in the following sections show that these areas have sufficient renewable generation potential and existing transmission capacity to provide all of the project participants' renewable energy requirements.

4.3.1 New Geothermal Resources – PG&E Area

The Energy Commission SVA Study estimates there are 468 MW of incremental Geothermal capacity located within PG&E's service territory. If developed, these resources could produce an additional 3.7 million MWh per year. The resource potential is concentrated in the counties of Sonoma, Lake and Napa. Table 4.1 summarizes data from the Energy Commission SVA Study showing the most likely incremental capacity for the geothermal resource areas within PG&E's service territory. The levelized project costs are from the developer's perspective and include transmission costs needed to connect the resources to the grid. The PTC is included in these cost figures. The data from the original Energy Commission study is contained in the Appendix, Table A.2.

Table 4.1: Likely Geothermal Development In PG&E's Service Territory

Geothermal Resource Area	Likely Incremental Capacity (MW)	Incremental Energy Production (MWH) *	Levelized Cost (2010 cents / kWh w/ PTC & Trans.)
Sulfur Bank Field, Clear Lake Area	43	339,012	5.74
Geysers, Lake County	100	788,400	5.74
Geysers, Sonoma County	300	2,365,200	8.16
Calistoga	25	197,100	8.19
Total PG&E	**468**	**3,689,712**	**7.42**

*Energy production is estimated based on a 90% capacity factor typical of geothermal resources.

The 143 MW of capacity in Lake County appears to have very positive project economics, based on the Energy Commission SVA Study's cost estimates. The 300 MW in the Geysers in Sonoma County and the 25 MW in Calistoga could be developed at costs that are at the high end of expected market prices during the next decade. These resources would likely require contracts at a premium above market prices of 1 to 1.5 cents per kWh in order for the resources to be developed.

4.3.2 NEW WIND RESOURCES – PG&E AREA

The Energy Commission's SVA Study estimates 407 MW or nearly 10,000 GWh per year of developable wind resources, but only approximately 13% of the generation potential is located within the PG&E service territory. Estimates of developable wind resources within the PG&E service territory are summarized in Table 4.2 below. Average MW output, or equivalent baseload capacity, is calculated as the MW capacity multiplied by the relevant capacity factors for each resource area. The original data from the Energy Commission SVA Study are contained in the Appendix, Table A.1. The Energy Commission SVA Study shows a 2010 levelized cost for these resources of 3.4 cents per kWh. The higher cost estimates contained in the more recent CPUC Study are instead used in Table 4.2 below because these include adjustments to account for recent increases in wind equipment costs.

Table 4.2: New Wind Resources in the PG&E Service Area

Location	Nameplate Capacity (MW)	Energy (MWh)	Average Output (MW)	2010 LCOE (cents/ kWh)
Solano	275	891,000	100	4.8
Altamont	132	428,000	50	4.8
Total PG&E	**407**	**1,319,000**	**150**	**4.8**

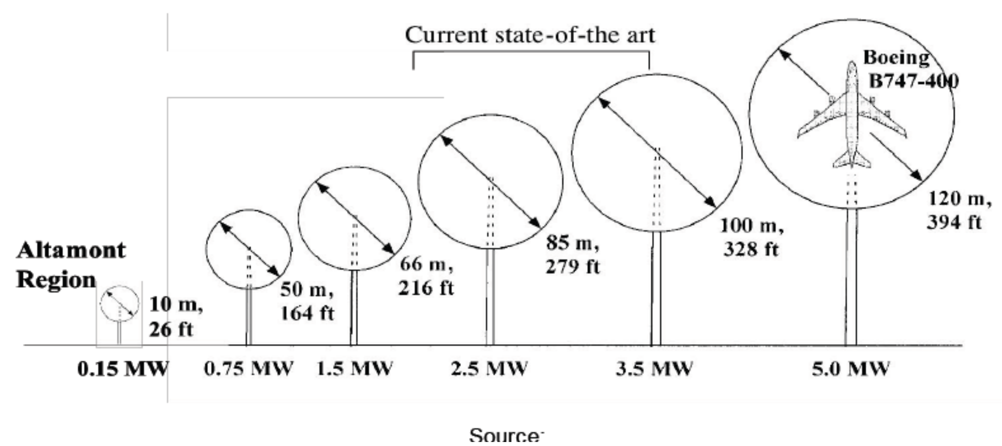
The market value for intermittent or "as available" resources such as wind energy is less than that of firm resources because there is little capacity value in an intermittent resource. NCI estimates capacity will be valued at between 1 to 1.5 cents per kWh through 2017, and the market value for as-available wind will be between 4.5 to 6.5 cents per kWh. Based on these projections, the 1.3 million MWh of wind potential located within PG&E’s service territory appears to be generally cost-competitive with electricity produced by gas fired generation, assuming the continuation of the PTC. Absent continuation of the PTC, private development of these resources may require securing contracts at premiums above market prices. The required premium could vary from a low of 0 to as high as 2 cents per kWh.

4.3.3 REPOWERED WIND RESOURCES – PG&E AREA

PG&E estimates nearly 300,000 MWh of incremental repowered wind will be available by 2014 from the Altamont pass.[9] The incremental wind production is expected to come online as existing contracts expire and the facilities are replaced with more efficient technology, improving capacity factors from the existing 18% for resources in this area to an estimated 30%. Repowering of existing wind facilities is a promising source of renewable energy supply based on economic and environmental considerations. Little or no incremental transmission is needed to support additional production from the Altamont area because PG&E transmission studies show transmission capacity currently exists and repowering can increase energy production with no increase in overall capacity; i.e., overall capacity factors are improved. Costs are expected to be below the average cost of new wind generation shown in Tables 3.3 and 3.4. Repowering is also expected to reduce avian mortality in the Altamont area.

The following figure illustrates the technological advancements that have occurred in wind turbine design since the majority of the turbines in the Altamont pass were deployed. A single modern day turbine can produce as much capacity as ten of the turbines in operation at Altamont.

Figure 5. Wind turbine size growth trend



Source: *California Energy Commission*

On September 22, 2005, the Alameda County Board of Supervisors amended the conditional use permits of the existing Altamont wind generation units to reduce

[9] Supplement to Pacific Gas and Electric Company’s 2005 Renewable Energy Procurement Plan, December 7, 2005

impacts to migratory birds caused by the existing wind generators. The revised conditions under the Avian Wildlife Protection Program & Schedule (AWPPS) require seasonal shutdowns of existing, non-repowered units and the eventual re-powering or removal of all existing units by 2018. Environmental Impact Reports must be prepared for repowered projects to address environmental impacts of the proposed repowering and the effectiveness of various strategies to reduce and minimize avian mortality.

The AWPPS sets a schedule for replacing existing turbines with new, repowered turbines. The schedule and estimated MW of wind capacity are summarized below:

Table 4.3: Schedule for Repowering of Altamont Wind Turbines

Year	Percent of Turbines Removed for Repower (Cumulative)	Existing Capacity Removed for Repower (Cumulative MW)	Incremental Production (MWh)
2009	10%	37	39,000
2013	35%	130	135,000
2015	85%	315	330,000
2018	100%	370	390,000

The estimated incremental production shown in Table 4.3 is calculated utilizing PG&E's estimates that the repowered turbines will operate at a 30% capacity factor and the existing turbines operate at an 18% capacity factor. The resulting projection for 330,000 MWh of incremental production in 2015 appears reasonable comparing to PG&E's estimate of 300,000 MWh by 2014.

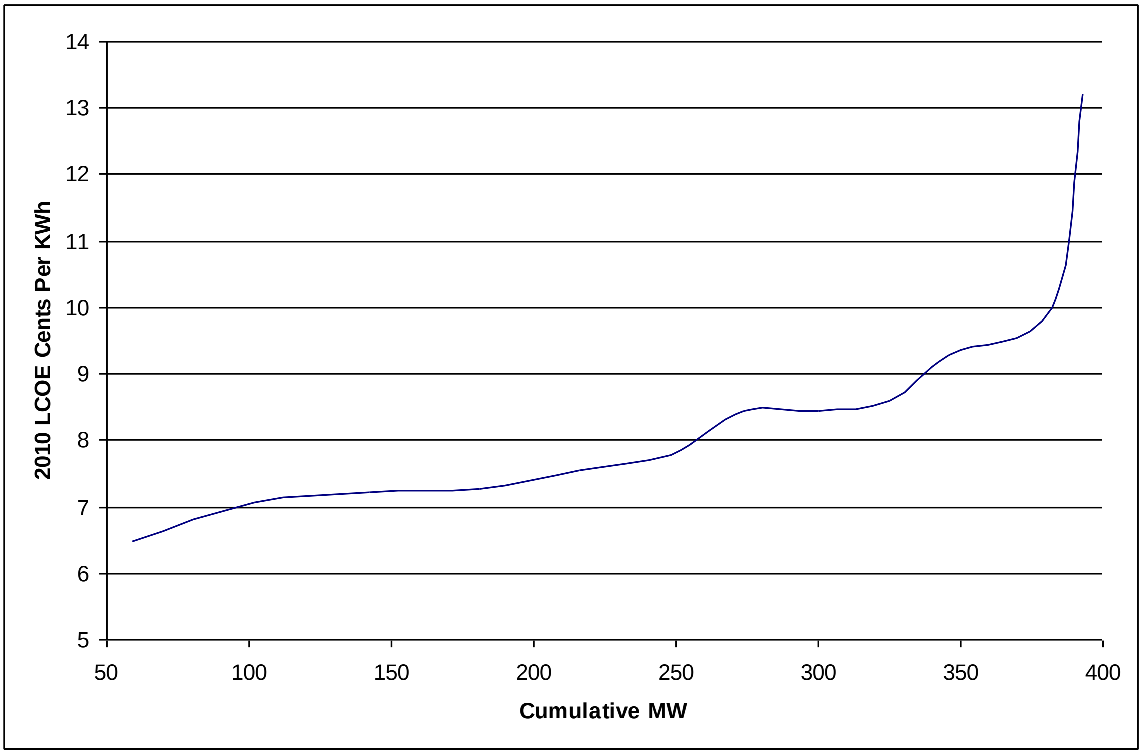
4.3.4 Biomass Resources[10] - PG&E Area

Energy from biomass includes combustion of forestry wood waste or methane produced from landfills, dairy farms, and wastewater treatment facilities. The Energy Commission's SVA study estimates nearly 400 MW of forestry biomass potential in PG&E's service territory, within relative proximity to existing transmission facilities, and 382 MW of this potential capacity is thought to be economically developable. Forestry biomass involves clearing of forests to reduce fire threat and property damage and burning the wood waste to produce electricity. These projects are baseload resources and are geographically dispersed throughout the PG&E service territory.

The Energy Commission SVA Study's cost data, reproduced in the Appendix, Table A.1, can be arranged graphically to show the quantity of biomass capacity that could be developed at various price points. Figure 4.1 shows approximately 100 MW of forestry biomass in the PG&E service area with an estimated levelized cost of energy in the 6 to 7 cents per kWh range. The annual energy production associated with this capacity is approximately 760,000 MWh, based on an 85% capacity factor. These resources are potentially cost competitive with other sources of renewable energy.

[10] Biomass potential from municipal solid waste is not included due to prevailing public concerns regarding incineration.

Figure 4.1: Cost of Forestry Biomass Resources in the PG&E Service Area



An earlier study commissioned by the Energy Commission in 2003 found an estimated 600,000 MWh per year of biomass resource potential in the PG&E service territory from landfill gas, wastewater treatment digesters and dairy farms (Biogas).[11] These resources are typically low cost but small scale projects in the 2 to 5 MW range. Levelized cost estimates range from 4 to 6 cents per kWh.[12] However, the small scale of these resources can make project development costs high on a dollar per MW basis. Contracting and administration costs may also limit the utilization of these resources.

The more recent Energy Commission SVA Study identified biogas potential for each county in California and places the incremental potential at 248 MW statewide. Approximately 70 MW are located within the PG&E service territory, which would equate to approximately 520,000 MWh per year of potential energy.

Table 4.4 summarizes the estimated biomass potential in PG&E's service area. The original data from the Energy Commission study are reproduced in the Appendix, Table A.1 (forestry biomass) and Table A.4 (biogas).

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[11] California Energy Commission *Renewable Resource Development Report*, 2003. Note, unlike the 2005 Strategic Value Analysis study, the resource potential in the Renewable Resources Development has not been screened for transmission impacts, and the commercially developable potential is likely less than the full 600 GWh per year shown..

[12] See Tables 7 and 7. Also, the Energy Commission's Renewable Resource Development Report, 2003 shows an estimated LCOE of 4.4 cents per kWh (2003 dollars) for landfill gas, excluding PTC.

Table 4.4: Developable Biomass Potential within the PG&E Service Territory

Fuel Type	Capacity (MW)	Energy (MWh)	2010 LCOE (cents per kWh)
Forestry biomass	102	760,000	6 to 7
Forestry biomass	146	1,090,000	7 to 8
Forestry biomass	77	575,000	8 to 9
Forestry biomass	57	425,000	9 to 10
Biogas	70	520,000	4 to 6
Total	**452**	**3,370,000**	**7.4**

Source: *Figures derived from data contained in Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report, CEC-500-2005-109-SD, June 2005*

4.3.5 NEW SOLAR – PG&E AREA

Utility scale solar is not expected to be a major contributor to the resource mix in the PG&E service territory due to the fact that the vast majority of technical potential for Concentrating Solar Power (CSP) is located in Southern California and the cost of photovoltaic (PV) solar is relatively high. CSP may play a limited role as a peaking resource, but its widescale utilization in the PG&E service territory would require additional transfer capability between Southern California and Northern California. Most solar resources in the PG&E service territory will take the form of distributed photovoltaic systems installed on rooftops of homes and businesses in response to incentives provided by state programs.

4.3.6 SUMMARY OF NEW RENEWABLE RESOURCES IN THE PG&E SERVICE AREA

Table 4.5 summarizes the utility-scale renewable resources anticipated to be developable in PG&E's service area during the next decade.[13]

Table 4.5: Summary of New Renewable Resources in the PG&E Service Area

Resource Type	Capacity (MW)	Energy (MWh)
Geothermal	468	3,689,712
New Wind	407	1,319,000
Repowered Wind	370	390,000
Biomass – Forestry	382	2,850,000
Biogas (LFG, WWT, Dairy)	70	520,000
Total	1,697	8,768,712

4.3.7 PG&E TRANSMISSION CONSTRAINTS

[13] Solar Photovoltaic not shown due to uncertainty regarding the role of "behind the meter" distributed generation in meeting the Renewable Portfolio Standard program.

PG&E's 2005 TRCR identifies eight of sixteen clusters as having existing transmission capacity sufficient to integrate new renewable resources, either as baseload or peaking resources.

Figure 4.2: PG&E Transmission Availability

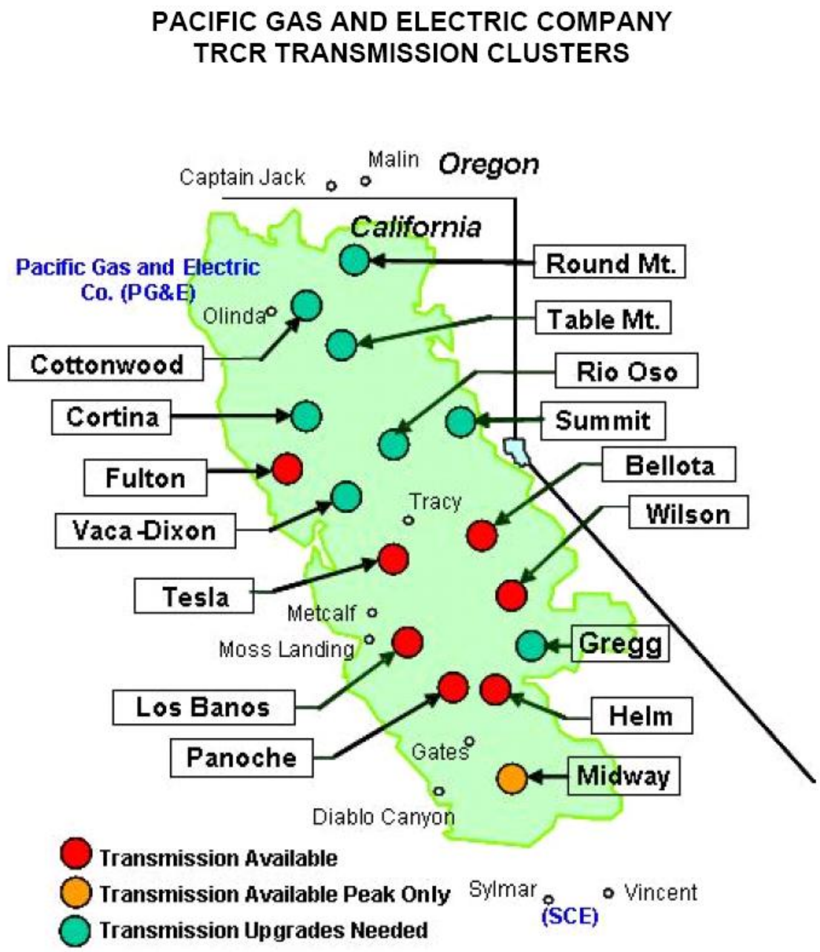
PACIFIC GAS AND ELECTRIC COMPANY
NORTHERN CALIFORNIA PROXY TRANSMISSION AVAILABILITY
(2005 TRANSMISSION RANKING COST REPORT)

Line No.	Cluster	Base Load Availability (MW)	Peaking Availability (MW)
1	Bellota	600	600
2	Fulton	200	700
3	Helm	100	600
4	Los Banos	50	450
5	Panoche	100	750
6	Tesla	1,000	1,000
7	Wilson	450	450
8	Midway	0	1,000

Source: *Supplement to Pacific Gas and Electric Company's 2005 Renewable Energy Procurement Plan, December 7, 2005*

The following figure shows the areas where existing transmission capacity exists and the other areas that would require transmission system upgrades.

Figure 4.3: PG&E Renewable Transmission Clusters



Source: *Pacific Gas And Electric Company Renewable Portfolio Standard 2006 Renewable Energy Procurement Plan, December 22, 2005*

In its 2006 Renewable Procurement Plan, PG&E overlays estimates of renewable energy potential and available transmission capacity by transmission hub in Northern California, showing that locations with significant renewable energy potential and existing transmission capability are not well aligned. The PG&E data raise the question of whether the utility's RPS goals can be achieved before additional transmission projects can be planned, sited, and constructed. A CCA in PG&E's service territory faces a similar challenge, albeit on a much smaller scale. Table 4.6 maps the renewable resource areas likely to be utilized by the project participants within the PG&E service territory to the relevant transmission cluster to show the MW that could be developed in advance of new transmission projects.

Table 4.6: Mapping of CCA Target Resource Areas to Transmission Cluster

Resource Area	Transmission Cluster	Available Transmission (MW Baseload)	Resource Potential (MW)	Net Developable (MW)
NP 15 Geothermal	Fulton	200	468	200
Solano Wind	Vaca Dixon	0	275	0
Altamont Wind[14]	Tesla	1,000	502	502
Forestry Biomass	Various	0	382	0
Biogas (LFG, WWTE, Dairy)[15]	Various	70	70	70
Total		**1,270**	**1,697**	**7,72**

Transmission constraints would appear to reduce the near term availability of resources to 772 MW from the 1,697 MW shown in Table 4.5. The 772 MW figure is what could be developed without major transmission system upgrades. Included in this figure is 333 MW of re-powered wind that will likely not be available by 2010, based on the schedule for repowering discussed in Section 4.3.3. The resources actually developable within the PG&E service area before 2010, assuming no major transmission upgrades are performed, are summarized in Table 4.7, below.

Table 4.7: Summary of Renewable Resource Availability By 2010 In PG&E Service Area, Including Existing Transmission Limitations

Resource	Available By 2010	
	MW	MWh
Geothermal	200	1,576,800
New Wind	132	428,000
Repowered Wind	37	97,236
Biomass (LFG, WWTE, Dairy)	70	525,000
Total	**439**	**2,627,036**

While these amounts are sufficient to meet the project participants' goals, they fall far short of the total demand for renewable resources in the PG&E area when one considers the utility's RPS needs. Our conclusion is that it is possible to meet the project participant's renewable energy goals, but a CCA will need to be very aggressive in pursuing the renewable resources that are available to ensure that PG&E does not lock up the available resources for its own portfolio needs. As discussed in Section 5, PG&E is in the process of identifying transmission upgrades that can be completed before 2010 to enable it to meet its RPS goals. Transmission upgrades will provide additional resource options for project participants as well. In the intermediate and longer term as

[14] Includes 370 MW of repowered Altamont wind capacity.

[15] These resources are generally nearer to load centers and relatively small scale; therefore it is assumed there would be no major transmission constraints on their development.

these transmission projects are built, project participants in the PG&E service area should be investigating development of wind resources in Solano County, the Tehachapi area and the Pacific Northwest; geothermal imports from Nevada and Imperial Valley; and Solar CSP imports from Southern California (Riverside and San Bernardino Counties).

4.4 CCAs Located within the SCE Service Area

Although the majority of California's renewable resource potential is located within SCE's service area, very little of the electricity produced by new renewable projects would be deliverable to load centers due to lack of current transmission capacity. With the exception of possible access to repowered wind facilities and local biomass projects, the renewable resource plans for demonstration project participants within SCE's service area will very much be dependent upon SCE's plans for expanding its transmission system to integrate renewable resources necessary for meeting its own RPS obligations. Other options for project participants include teaming with area municipal utilities (e.g., LADWP, Anaheim or Burbank) to obtain renewable energy pursuant to solicitations currently underway, contracts with existing qualifying facilities whose contracts with SCE are expiring, and the potential use of unbundled renewable energy certificates to satisfy the CCA's renewable energy needs.

Based on resource potential and existing transmission availability, the most likely sources of new renewable energy for project participants in the SCE service area are:

- Wind resources in the Tehachapi area (phases 1 and 2)
- Repowered wind in Riverside and San Bernardino Counties
- Local biomass

SCE area renewable resources identified by the Energy Commission SVA Study and the CPUC Study are discussed below.

4.4.1 New Geothermal – SCE Area

There is approximately 174 MW of new geothermal capacity identified in the Energy Commission SVA Study located within the SCE service area. The transmission impact screen applied in that study found development of these resources would degrade transmission system reliability, and these resources did not meet the study's criteria for recommended development. Table 4.8 summarizes the geothermal resource potential in SCE's service area. The original Energy Commission data are contained in the Appendix, Table A.3.

Table 4.8: Incremental Geothermal Resources in the SCE Service Area

Geothermal Resource Area	Likely Incremental Capacity (MW)	Incremental Energy Production (MWH) *	Levelized Cost (2010 cents / kWh w/ PTC & Trans.)
Long Valley Mono County	71	559,764	4.37
Coso Hot Spring Inyo County	55	433,620	7.85
Randsburg	48	378,432	6.49

Geothermal Resource Area	Likely Incremental Capacity (MW)	Incremental Energy Production (MWH) *	Levelized Cost (2010 cents / kWh w/ PTC & Trans.)
Total SCE	**174**	**1,371,816**	**6.1**

For planning purposes, none of these resources are considered to be economically developable because of high transmission costs. Project participants should monitor SCE's transmission planning process for proposed transmission upgrades that may change this conclusion because the generation costs of these resources appear relatively attractive.

4.4.2 NEW WIND – SCE AREA

The SCE area is home to the vast wind potential located in the Tehachapi wind resource area as well as other high wind sites in San Bernardino and Riverside Counties. The resource potential in the Tehachapi area is estimated at 4,500 MW, and SCE has worked with other stakeholders to develop a phased plan for expanding its transmission system to enable interconnection and delivery of these resources. The Energy Commission SVA Study projected 1,200 MW would be developable by 2010. The remaining potential would be available as the later phases of SCE's transmission plan become operational. For sake of comparison, the CPUC Study estimates that 1,000 MW of Tehachapi wind and 168 MW of San Bernardino wind will be available by 2010. Table 4.9 summarizes the estimated developable wind potential in SCE's service area.[16]

Table 4.9: New Wind Resources in the SCE Service Area

Location	Nameplate Capacity (MW)	Energy (MWh)	Average Output (MW)	2010 LCOE (cents/ kWh)
Tehachapi Phase 1	700	1,839,600	210	4.8
Tehachapi Phase 2	900	2,365,200	300	4.8
Tehachapi Phase 3	1,700	4,467,600	510	4.8
Tehachapi Phase 4	1,200	3,153,600	360	4.8
Riverside	1,416	3,721,248	425	4.8
San Bernardino	168	441,504	50	4.8
Total SCE	**6,084**	**15,988,752**	**1,855**	**4.8**

4.4.3 REPOWERED WIND – SCE AREA

SCE has estimated 576,000 MWh of incremental re-powered wind energy could be online between 2006 and 2009 as a result of repowering or expanding existing wind

[16] The various phases of the transmission expansion plan for integrating Tehachapi wind resources are described in Section 5.2.

projects under contract with SCE. Wind repowering is a good potential source of renewable energy in the near term because incremental capacity can be brought online relatively quickly, and transmission capacity already exists to interconnect the generation facilities. Very little, if any, of this potential has been bid into SCE's renewable solicitations, and the potential appears largely untapped and available to CCAs.[17]

4.4.4 BIOMASS – SCE AREA

The Energy Commission SVA Study identified approximately 150 MW of biomass potential in the SCE service area, which corresponds to approximately 1 million MWh of potential generation per year. The majority is potential landfill gas generation in Los Angeles, Orange, Riverside and San Bernardino Counties. There also exists modest potential generation capacity from dairy digesters and wastewater treatment facilities. Table 4.10 summarizes the potential biomass resources in SCE's service area. The original Energy Commission data are reproduced in the Appendix, Table A.4.

Table 4.10: Incremental Biomass Generation in the SCE Service Area

Location	Capacity (MW)	Energy (MWh)	2010 LCOE (cents per kWh)
Los Angeles	25	186,150	4 to 6
Orange	33	245,718	4 to 6
Riverside	28	208,488	4 to 6
San Bernardino	31	230,826	4 to 6
Other	30	223,380	4 to 6
Total	**147**	**1,094,562**	**5**

4.4.5 SOLAR – SCE AREA

In addition to the PV potential discussed in Section 3.2.3, there exists significant potential for utility scale concentrating solar power (CSP) facilities in the desert areas of Southern California, located within SCE's service area. Solar generation provides high value peaking power, and expected costs range from 6 cents per kWh reported in the Energy Commission SVA study to 9 cents per kWh estimated in the CPUC Study, both assuming continuation of the investment tax credit. The market value of solar energy is approximately 15% higher than baseload electricity because solar production coincides with periods of peak electricity demand. Both SCE and SDG&E have announced plans to contract with CSP resources located in the Southern California deserts. The contract prices have not been publicly disclosed, but are reportedly competitive enough that public goods surcharge subsidies will not be necessary.

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[17] Southern California Edison Company's 2006 Renewables Portfolio Standard Procurement Plan, December 22, 2005, page 19

The total technical potential for solar generation is truly massive at an estimated 151,000 MW or 330,500,000 MWh per year.[18] Only a minute fraction of this potential is projected to be developed according the Energy Commission SVA Study, as summarized in Table 4.11.

Table 4.11: Concentrating Solar Power Resource in the SCE Service Territory

Location	Capacity (MW)	Energy (MWh)	2010 LCOE (cents per kWh)
Riverside	599	1,311,810	6 to 9
San Bernardino	447	978,930	6 to9
Total	**1,046**	**2,290,740**	**7.5**

4.4.6 SUMMARY OF NEW RENEWABLE RESOURCES IN THE SCE SERVICE AREA

The total estimate for the SCE service area is approximately 7,500 MW of renewable capacity and 20,000,000 MWh of annual energy production. Geothermal resources are excluded from these estimates due to the Energy Commission SVA Study's conclusion regarding adverse transmission impacts. Wind energy accounts for more than three fourths of the energy potential, with nearly three fourths of the wind potential located within the Tehachapi area. The data are summarized in Table 4.12, below.

Table 4.12: Summary of New Renewable Resources in the SCE Service Area

Resource Type	Capacity (MW)	Energy (MWh)
Geothermal	0	0
New Wind	6,084	15,988,752
Repowered Wind	220	576,000
Biomass – LFG, WWT, Dairy	147	1,094,562
Solar – CSP	1,046	2,290,740
Total	**7,497**	**19,950,054**

Generation costs for these resources are relatively low relative to market value. Absent transmission constraints which are discussed below, the resources shown in Table 4.12 appear economically developable. Because the renewable resources in SCE's service territory have relatively low generation costs, transmission will be the limiting factor in their utilization. With the possible exception of small scale biomass and repowered wind, all of the renewable resources are expected to require transmission system upgrades before being developed.

4.4.7 SCE 2005 TRANSMISSION RANKING COST REPORT

[18] Developing Cost-Effective Solar Resources with Electricity System Benefits; In support of the 2005 Integrated Energy Policy Report; Energy Commission Staff Paper, George Simons, June 2005

SCE's 2005 TRCR shows available transmission capability in only two of the 13 geographic clusters corresponding to renewable resource development areas. Between 80 and 135 MW could be available in the Victorville area and 10 MW could be available for integrating renewable resources at the California/ Nevada Border, without the need for expansive system upgrades. Generally speaking, new renewable resource development will require transmission system upgrades that may take from four to seven years to place into operation. SCE reports it will need to complete transmission system upgrades for all of the renewable energy contracts it has already executed from projects within its service area in order to meet its RPS targets by 2010 and that virtually no incremental renewable resources can be integrated without new transmission being built.[19] Transmission upgrades are expected to be completed in the 2008 to 2013 timeframe.

CCAs within SCE's service area should investigate the opportunity to contract with existing wind generators as their existing contracts with SCE expire and the facilities are repowered or expanded. Sufficient repowered wind potential exists to serve the renewable goals of the project participants in SCE's service area. Biomass should also be considered for near term development. Otherwise, achieving the participants' renewable energy objectives will be dependent upon SCE's transmission expansion plans for access to new renewable energy resources. The potential use of unbundled renewable energy certificates, if allowed by the CPUC, could also enable Southern California CCAs to meet their near term renewable energy requirements. In the intermediate and longer term, project participants in SCE's service area should be investigating development of wind resources in the Tehachapi and San Gorgonio areas, CSP in Riverside and San Bernardino Counties, geothermal resources located in Imperial Valley, and geothermal imports from Nevada.

Table 4.13: Summary of Renewable Resource Availability By 2010 In SCE Service Area, Including Existing Transmission Limitations

Resource	Available By 2010	
	MW	MWh
Tehachapi Wind (Phases 1 and 2)	1,600	4,204,800
Repowered Wind	220	576,000
Biomass (LFG, WWTE, Dairy)	147	1,094,562
Total	**1,967**	**5,875,362**

4.5 CCAs Located within the SDG&E Service Area

Relatively little renewable resource potential exists within the SDG&E service area, and SDG&E's procurement needs are virtually certain to exhaust any near term potential that does exist. Similar to the situation in SCE's service area, project participants in the SDG&E service area will be dependent upon SDG&E's efforts to expand its transmission

[19] Southern California Edison Company's Supplement to its Renewable Procurement Plan 2005 – 2014, December 7, 2005

system needed to access renewable resource areas in nearby Imperial County and imports from the SCE system.

The Energy Commission SVA study shows 206 MW of developable renewable capacity in the SDG&E service area, comprised of 150 MW of wind, 21 MW of biomass and 35 MW of concentrating solar power. These resources are summarized in Table 4.14.

Table 4.14: Incremental Renewable Resources in the SDG&E Service Area

Resource Type	Capacity (MW)	Energy (MWh)
Wind	150	394,200
Biomass – LFG, WWT, Dairy	21	156,366
Solar – CSP	35	76,650
Total	**206**	**627,216**

Based on resource potential and existing or planned transmission availability, the most likely sources of renewable energy for project participants in the SDG&E service area are:

- Geothermal imports from the Imperial Valley
- Wind resources in Eastern San Diego County
- Local biomass

The potential for utilizing geothermal resources in Imperial Valley to serve loads in the San Diego area is discussed in Section VI.F. Access to this resource area is dependent upon the planned expansion by SDG&E of its transmission system, which SDG&E maintains is critical to its ability to meet its RPS obligations. The planned transmission upgrades would enable a total of 1,290 MW of geothermal resource capacity to be utilized within the San Diego area by 2017.

4.5.1 SDG&E 2006 Transmission Cost Ranking Report

SDG&E's Transmission Ranking Cost Ranking Reports for 2004 and 2005 show that transmission system upgrades will be required to accommodate integration of new renewable resources for delivery to load within the SDG&E system. The ability to transmit energy from renewable wind resources located in SDG&E's eastern service area is limited by the existing 69 KV system. The 2005 TRCR shows a potential for approximately 937 MW of wind energy in the southeastern portion of SDG&E's service area and 1,045 MW of projects of various renewable technologies in the Imperial Valley area. The SDG&E studies assume that the Sunrise Powerlink will be in place by 2010 and that a 500 kV tap will be constructed along the existing Southwest Powerlink line to accommodate renewable resource potential in eastern San Diego County.[20]

[20] SDG&E Application for CPCN for the Sunrise Powerlink Transmission Project, Volume 2, page IV-13.

In the immediate term, CCAs in the SDG&E service area should investigate opportunities for local biomass resource development, which may be accommodated without major transmission system upgrades. Unbundled renewable energy certificates should also be considered, if ultimately allowed by the CPUC for RPS compliance. In the intermediate and longer term, project participants in the SDG&E service area should investigate imports of geothermal resources from the Imperial Valley, wind resources in Eastern San Diego County, Solar CSP resources in San Diego, Imperial, Riverside and San Bernardino Counties and imports of wind resources from the Tehachapi area and Riverside County.

Table 4.16: Summary of Renewable Resource Availability By 2010 In SDG&E Service Area, Including Existing Transmission Limitations and Planned Upgrades

Resource	Available By 2010	
	MW	MWh
Wind	150	394,200
Biomass (LFG, WWTE, Dairy)	21	156,366
Geothermal (Imperial)	645	5,085,180
Total	**816**	**5,635,746**

5. TRANSMISSION EXPANSION PLANS

This section summarizes the transmission expansion plans of the investor-owned utilities that are relevant to expanding access to renewable resources.

5.1 PG&E TRANSMISSION EXPANSION PLANS

Large scale renewable resource development in Northern California will be dependent upon transmission projects initiated by PG&E to access renewable resources to meet its RPS requirements. CCAs within PG&E's footprint will be in competition with PG&E for access to the limited renewable energy supplies that can be delivered utilizing existing transmission capacity. In a constrained supply environment, the CCA has the advantage of needing to procure fewer megawatts of renewable capacity in absolute terms, even if the CCA's renewable energy target is greater than PG&E's on a percentage basis. CCAs may be able to meet their renewable energy goals without being dependent upon PG&E transmission plans if the CCA can execute contracts with developers before PG&E locks up all of the available and economically attractive resources. In order to effectively compete with PG&E, the CCA should strive for a renewable energy procurement process that is quicker and more efficient than PG&E's. However, near-term displacement of PG&E's renewable energy procurement may not meet the broader policy objectives of the CCA. If the CCA competes unsuccessfully with PG&E for available resources or if the true motivation is to expand overall renewable energy utilization (i.e., statewide), the CCA will be dependent upon PG&E's renewable energy transmission plans to fulfill its renewable resource procurement objectives.

5.1.1 PG&E TRANSMISSION UPGRADES TO SUPPORT 2010 RPS

PG&E has identified several potential upgrades that would be needed under more than one scenario of renewable energy development. PG&E refers to these common upgrades as "pinch points" in the transmission system. PG&E has identified the following network facilities where upgrades are common to several clusters of renewable energy development:

- Cortina – Vaca-Dixon 230 kV line;
- Shiloh-Contra Costa 230 kV line;
- Table Mountain – Vaca-Dixon 500 kV line;
- Wesley – Los Banos 230 kV line;
- Tesla – Los Banos 500 kV line;
- Midway – Gates and Midway – Los Banos 500 kV lines

PG&E has preliminarily identified several potential reinforcements to upgrade these facilities, which can be brought online in a relatively short period of time and can be sized to match generation resources as they materialize.[21] PG&E reports that in 2006 it will identify, prioritize, propose and begin execution of transmission projects that can

[21] For a list, see December 7 Supplement, page 22

serve multiple purposes in accessing renewable energy from various locations on its system to help meet the 2010 RPS goals.

5.1.2 PG&E TRANSMISSION OPTIONS TO EXPAND IMPORTS FROM SOUTHERN CALIFORNIA

SCE has plans underway to build transmission needed to integrate 4,000 MW of wind resources from the Tehachapi Wind Resource Area and 500 MW from the Antelope Valley. PG&E has evaluated its ability to import up to 2,000 MW of Tehachapi wind to its service area and found that insufficient transmission capacity exists over Paths 15 and 26 during system off-peak conditions when the prevalent flow is in the South to North direction. During system peak conditions with the Path 26 flow is in the North to South direction, the additional 2,000 MW of import at the Midway substation (interconnection between PG&E and SCE systems), is not expected to require upgrades on the PG&E system. As part of Tehachapi Collaborative Study Group, PG&E identified three alternative plans for importing 2,000 MW of Tehachapi wind into the PG&E service territory, but to date PG&E has not made commitments to developing any of these alternatives. It should be noted that increasing the transfer capability between the PG&E and SCE systems, which would be needed for PG&E to access Tehachapi wind, would also enable import of other renewable energy projects located in Southern California.

5.1.3 PG&E TRANSMISSION PROJECTS NEEDED FROM IMPORTS FROM OUT OF STATE

According to PG&E, it is actively participating in a regional transmission planning group (Northwest Transmission Assessment Committee or "NTAC") that is studying ten different transmission options to provide between 300 and 3,000 MW of additional import capability into California. For reference, these options are listed below:

1) DC underwater cable from Prince Rupert Island to Vancouver Island to the San Francisco Bay Area;[22]

2) DC underwater cable from Vancouver Island to the Olympic Peninsula with 500 kV AC line to northern California;

3) 500 kV AC line from northern Alberta/ BC to northern California using westside route;

4) 500 kV AC line from South/ Central BC to northern California using mid-WA route;

5) 500 kV AC line from northern Alberta to northern California using central route;

6) AC/ DC line from northern Alberta to northern California

7) AC/ DC line from northern Alberta to LA via Midpoint Substation;

[22] Pacific Gas & Electric is exploring a variation of Option 1 with Sea Breeze Pacific West Coast Cable, Low Pressure to build a 650 mile, 1,600 MW undersea cable from Portland, Oregon to the San Francisco Bay Area.

8) DC line from northern Alberta to southern California through Townsend Substation;

9) DC line from northern Alberta to northern California through Townsend Substation; and

10) Minor upgrades on existing transmission system from Canada to California.

Source: *Supplement to Pacific Gas and Electric Company's 2005 Renewable Energy Procurement Plan*, December 7, 2005

5.2 SCE TRANSMISSION EXPANSION PLANS

SCE has filed applications for Certificates of Public Convenience and Necessity (CPCN) for Segments 1, 2, and 3 of the Antelope Transmission Project with the CPUC. After expansion, the system will be able to accommodate 700 MW of incremental wind capacity by 2008. Approximately 1,700 MW of wind generation requests are already in the CAISO interconnection queue that are not under contract with SCE.[23] The contract status of these resources is not known, and it may be possible for CCAs to negotiate power purchase agreements with the developers already in the queue to obtain access to Tehachapi wind resources ahead of SCE.

SCE has performed conceptual studies for integrating up to 4,500 MW of wind generation from the Tehachapi region. Four options have been identified as part of a collaborative transmission planning effort known as the Tehachapi Collaborative Study Group. The phases would be completed as follows:

Table 5.1: Transmission Expansion for Integrating Tehachapi Wind Resources

Phase	Incremental Capacity (MW)	Completion Date
Phase 1	700	2008
Phase 2	900	2010
Phase 3	1,700	2014
Phase 4	1,200	2020
Total	4,500	

Source*: Achieving A 33% Renewable Energy Target; J.Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005.*

A final report from the Tehachapi Collaborative Study Group is anticipated to be completed in the first half of 2006.

5.3 SDG&E TRANSMISSION EXPANSION PLANS

SDG&E filed an application for a Certificate of Public Convenience and Necessity in December 2005 for the Sunrise Power Link project, which will provide a 500 kV

[23] Southern California Edison Company's Supplement to its Renewable Procurement Plan 2005 – 2014, December 7, 2005, page 4

interconnection with Imperial Valley to be in place by 2010. The project would be designed to import up to 2,000 MW into the SDG&E system. The reported benefits of the project are to provide SDG&E with access to renewable energy to meet its 2010 targets and to reduce the need for or replace reliability must run resources in the San Diego area.

The Sunrise Powerlink is included in conceptual plans for integrating geothermal resources in Imperial Valley developed through the Imperial Valley Study Group collaborative transmission planning effort. The conceptual plans include transmission upgrades necessary to integrate up to 2,200 MW of geothermal or other renewable generation from the Imperial Valley. The plans include new transmission into San Diego, new transmission into SCE, and new transmission within the Imperial Irrigation District. Estimated completion dates for the various phases of the projects needed to integrate Imperial Valley Geothermal resources are shown in Table 5.2.

Table 5.2: Transmission Expansion for Integrating Imperial Valley Geothermal Resources

Phase	Incremental Capacity (MW)	Completion Date
Phase 1	645	2010
Phase 2	645	2016
Phase 3	910	2020
Total	2,200	

Source*: Achieving A 33% Renewable Energy Target; J.Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005.*

6 CCA FINANCING OF RENEWABLE FACILITIES

This section describes opportunities for CCAs to finance generation projects or power purchases and describes certain restrictions applicable to such financings.

6.1 USE OF TAX EXEMPT DEBT TO FINANCE GENERATION FACILITIES

A CCA is a public agency authorized to provide electricity to retail customers within its jurisdictional boundaries. CCAs may purchase electricity from private entities or public entities and may build or buy electric generation facilities necessary to furnish electricity to their customers. As a public agency, a CCA may utilize electricity produced from facilities financed with tax-exempt debt. Internal Revenue Service restrictions limit use of tax exempt financing for public purposes, which would include providing electric service to customers of the CCA. Generally, a private business use exists, thus jeopardizing the tax-exempt status of bonds utilized to finance a facility, if a non-governmental entity acquires special legal entitlements to use a facility, such as through an ownership or leasehold interest in a facility, or has rights to the facility that rise to a level comparable to ownership or leasehold right. A CCA would be able sell surplus power from generation projects financed with tax-exempt debt to participants in the wholesale power markets on a short-term basis, regardless of whether the buyers are private or governmental entities, as long as the contract does not transfer to the private buyer the benefits of owning the facility and the burdens of paying the debt service on bonds used to finance the facility. Short term sales of surplus power would clearly not meet the “benefits and burdens” test triggering private use restrictions.

Contract structures with “take-or-pay” or ”must-take” provisions could be deemed to meet the benefits and burdens test. IRS rules allow limited sales to private entities for these types of contracts without jeopardizing the tax-exempt status of the debt issuance. One such exception is that sales to private entities that do not exceed 3 years in duration are permissible, as long as the project was not financed for the principal purpose of providing the facility for use by the nongovernmental entity. Additionally, small purchases of 1 percent or less of the average annual debt service on all outstanding tax-exempt bonds issued to finance the facility are permitted without triggering private use restrictions, regardless of length of term. The rules on private use bonds also allow for up to 10% private participation in a bond issuance without triggering the private use rules. Specifically, the private use test is met if more than 10 percent of the proceeds of the issue are to be used for any private business use, or if the payment of debt service on more than 10 percent of the proceeds of an issue is directly or indirectly: (1) secured by an interest in property used for a private business use, (2) secured by an interest in payments in respect of such property, or (3) derived from payments in respect of property or borrowed money used for a private business.

6.2 USE OF REVENUE BONDS TO FINANCE GENERATION FACILITIES

Revenue bonds are typically used for generation projects financed by public agencies. Revenue bonds are debt instruments that are backed by the revenues derived from their use, in this case, by revenues generated by the sale of electricity from the project financed by the bonds. Bond underwriters will carefully examine the security of the revenue stream to ensure the bonds will be repaid. Before selling revenue bonds, a CCA must be able to demonstrate it has a broad and stable base of customers that will provide revenues for repayment of the bonds; it has an enforceable means of recovering potentially stranded costs from customers that leave the program; or it has another credible means of repaying the bonds. Typical bond covenants required as a condition of issuing revenue bonds would impose obligations on the CCA to protect the interests of bondholders, for example by requiring the CCA to set rates at a level sufficient to ensure repayment of the bonds.

A CCA may incur debt directly to finance generation projects or it may enter into agreements to purchase output from generation facilities financed by another public agency. A recent example of the latter approach is the Magnolia generation project, financed by issuance of 30-year revenue bonds by the Southern California Public Power Agency ("SCPPA"). The project output is sold to six municipalities that are SCPPA members under "take-or-pay" contracts, whereby participants are entitled to power output and obligated to make payments for their proportionate share of operating and maintenance expenses and debt service. The contracts cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders as long as any bonds issued by the project remain outstanding. The bonds are also insured. The financing structure of the bonds provides a secure revenue stream for bondholders, resulting in a triple-A credit rating and an all-in interest cost of 4.9%. The debt associated with financing the Magnolia project, as well as ownership of the facility, resides entirely with SCPPA and is not carried on the books of any of the SCPPA members. This accounting treatment is appropriate, i.e., the take-or-pay contract does not transfer financial responsibility for the project to the CCA, as long as the JPA that finances the project does not depend upon revenue from the CCA to continue its existence.

6.3 CLEAN RENEWABLE ENERGY BONDS (CREBS)

The 2005 federal Energy Policy Act instituted a new program of interest free loans available for public agencies to develop renewable energy resources. On December 12, 2005, the United States Internal Revenue Service (IRS) issued Notice 2005-98, which solicited applications for allocations of the CREB limitation specified under Section 54 of the Internal Revenue Code. Section 54 authorizes up to $800 million of tax credit bonds to be issued by qualified issuers for the purpose of financing certain renewable energy projects. Project-specific applications must be submitted to the IRS by April 26, 2006 for those interested in attaining an allocation of the CREB limitation. The limited funding will likely be fully subscribed before California CCAs are in a position to apply for the loans; however, if this new program is expanded, a CCA could utilize such bonds to finance renewable generation projects without incurring interest costs.

Unlike traditional debt issuances, which pay a specified rate of return (interest) to purchasers, CREBs will provide their holders with eligibility for tax credits. Credit rates, as well as maximum bond terms, will be determined by the Secretary of the Treasury (Secretary) on a daily basis (available at www.publicdebt.treas.gov) and will be set at amounts that "will permit the issuance of clean renewable energy bonds with a specified maturity or redemption date without discount and without interest cost to the issuer." Bonds issued during three-month periods ending on credit allowance dates (March 15, June 15, September 15 and December 15) will receive ratable credits based on the portion of the aforementioned three-month periods during which the bond was outstanding; the credit for each three-month period ending on a credit allowance date will be equal to 25% of the applicable annual credit. Thereafter, annual credit amounts afforded bond holders will be equal to the credit rate for the day on which the bond was sold multiplied by the outstanding face amount of the bond. Credit limits apply based on provisions outlined in Section 54 of the Tax Code.

Qualified CREB issuers are categorized as one of three entities, which include: 1) clean renewable energy bond lenders; 2) cooperative electric companies; and 3) governmental bodies. CREB lenders are cooperatives, and their controlled affiliates, that were in existence as of February 1, 2002 and are owned by or have outstanding loans to 100 or more cooperative electric companies. Cooperative electric companies are determined to be mutual or cooperative electric companies or not-for-profit electric utilities that have received a loan or loan guarantee under the Rural Electrification Act, such as the Tennessee Valley Authority. Finally, governmental bodies are defined as "any State, territory, possession of the U.S., the District of Columbia, Indian tribal government or any political subdivision thereof."

Qualified borrowers, which include mutual or cooperative electric companies or governmental bodies, may use CREB funds to develop any of the following facilities, such as: 1) wind facilities, 2) closed-loop biomass facilities, 3) open-loop biomass facilities, 4) geothermal or solar facilities, 5) small irrigation power facilities, 6) landfill gas facilities, 7) trash combustion facilities, 8) refined coal production facilities, or 9) qualified hydropower facilities. With respect to the $800 million CREB limitation, up to $500 million may be allocated to finance qualified projects from borrowers that are determined to be governmental bodies.

Of the total proceeds received by a qualified borrower in connection with the CREB program, 95% must be used for capital expenditures related to the development of an aforementioned qualified facility. Within six months of bond issuance, a binding commitment to spend at least 10% of the bond sale proceeds must be made with a third party, or if proceeds of the bond sale are to be loaned to two or more qualified borrowers, such qualified borrowers must enter into a binding commitment to spend the aforementioned amount within six months of loan origination. All proceeds must be spent within five years of the date of bond issuance unless an extension is granted by the Secretary.

Projects for governmental bodies and mutual or cooperative electric companies will be allocated the full amount of requested CREBs beginning with the project(s) for which the smallest amount of the CREB limitation has been requested. This allocation will continue in ascending order until the total CREB limitation has been allocated. During this allocation process, as soon as the $500 million aggregate maximum is reached for governmental bodies, all remaining CREBs will be allocated to mutual or cooperative electric companies. Qualified projects located at the same site and owned by the same qualified borrower will be treated as a single project.

6.4 Use of Tax Exempt Bonds to Prepay for Electricity Purchases

Municipal gas and electric utilities may use tax-exempt debt issuances for prepayment of natural gas or electric supplies if such supplies are predominantly used to supply gas or electricity to their retail customers.[24] Prepayment can enable a municipal utility to obtain secure gas or electric supplies at a competitive price. The economic benefit to the issuer should be roughly equivalent to the difference between the present value of the periodic payments that would ordinarily be made over the term of the sale, discounted at the seller's cost of capital versus the same series of payments discounted at the issuer's cost of debt. Prepayments can reduce energy supply costs by five to fifteen percent, depending upon the seller's perceived cost of capital, the issuer's cost of debt, and how the prepayment would be treated for tax purposes by the seller.

The following summarizes the types of natural gas and electric pre-payments that would qualify for tax-exempt financing.

6.4.1 ELECTRICITY PREPAYMENTS

An electricity prepayment would qualify for tax-exempt debt financing if it is made by or for one or more utilities that are owned by a governmental entity to purchase a supply of electricity and at least 90 percent of the prepaid electricity financed by the issue is used for a qualifying use. Electricity is used for a qualifying use if it is to be: 1) furnished to retail electric customers of the issuing municipal utility who are located in the electricity service area of the issuing municipal utility; or 2) sold to a utility that is owned by a governmental entity and furnished to retail electric customers of the purchaser who are located in the electricity service area of the purchaser. Service area is defined as any area throughout which the utility provided, at all times during the 5-year period ending on the issue date, natural gas transmission and distribution service or electricity distribution service. Service area also includes any area recognized as the service area of the utility under state or federal law. The latter definition is not subject to the five year service requirement.

6.4.2 NATURAL GAS PREPAYMENTS

A natural gas prepayment would qualify if it is made by or for one or more utilities that are owned by a governmental entity to purchase a supply of natural gas and at least 90 percent of the prepaid natural gas financed by the issue is used for a qualifying use. Natural gas is used for a qualifying use if it is to be:

(i) Furnished to retail gas customers of the issuing municipal utility who are located in the natural gas service area of the issuing municipal utility;

ii) Used by the issuing municipal utility to produce electricity that will be furnished to retail electric customers of the issuing municipal utility who are located in the electricity service area of the issuing municipal utility;

(iii) Used by the issuing municipal utility to produce electricity that will be sold to a utility that is owned by a governmental entity and furnished to retail electric customer of the purchaser who are located in the electricity service area of the purchaser;

[24] 26 Code of Federal Regulations Part 1

(iv) Sold to a utility that is owned by a governmental entity if the purchaser meets the requirements of (i) through (iii); or

(v) Used to fuel the pipeline transportation of the prepaid gas supply.

It is not clear whether a CCA would qualify as a municipal utility under the current regulations, although there is no obvious reason why such financing should not be available to energy pre-purchases by a CCA. A CCA is similar in many respects to a municipal utility that provides electric distribution service; a CCA has a defined service area, in which it has certain powers to provide retail electric service and also has certain service obligations that are defined by state law. A CCA should seek additional guidance from qualified tax counsel and the IRS if it is contemplating use of tax-exempt bonds to prepay for gas or electricity.

7 CONCLUSIONS AND RECOMMENDATIONS

Project participants in the PG&E and SCE service areas should be able to meet their 2010 renewable requirements from resources internal to the service area. Project participants in the SDG&E service area will likely need to rely on imports of renewable energy from the Imperial Valley or possibly utilization of unbundled renewable energy certificates to meet their 2010 requirements. Project participants should also understand that competition for renewable resources from other load serving entities, particularly the local distribution utilities (PG&E, SCE, and SDG&E) seeking to meet their own renewable energy requirements, could hinder CCA renewable procurement efforts.

Project participants should focus their renewable resource planning efforts for new resources on the following areas:

Project Participants in the PG&E Service Area

Near Term

- Geothermal in Lake and Sonoma Counties
- Expansion and re-powering of wind resources in Alameda County
- Local biomass projects

Longer Term

- Wind resources in Solano County
- Wind imports from the Tehachapi Area
- Wind imports from the Pacific Northwest
- Geothermal imports from Nevada
- Geothermal imports from the Imperial Valley
- Solar CSP imports from Southern California (Riverside and San Bernardino Counties)

Project Participants in the SCE Service Area

Near Term

- Wind resources in the Tehachapi area (Phases 1 and 2)
- Re-powered wind in Riverside and San Bernardino Counties
- Local biomass projects

Longer Term

- Wind resources in the Tehachapi area (Phase 3) and Riverside County
- Solar CSP in Riverside and San Bernardino Counties
- Geothermal imports from the Imperial Valley
- Geothermal imports from Nevada

Project Participants in the SDG&E Area

Near Term

- Geothermal imports from the Imperial Valley
- Wind resources in Eastern San Diego County
- Local biomass projects

Longer Term

- Wind imports from the Tehachapi Area and Riverside County
- Solar CSP in San Diego
- Solar CSP imports from Imperial, Riverside and San Bernardino Counties

While this report focuses on new renewable resource potential, existing renewable resources from "Qualifying Facilities" that have historically been under contract with the investor-owned utilities are also viable sources of renewable energy for project participants as these contracts expire over the next several years.

Project participants may use tax-exempt financing to reduce the cost of procuring renewable energy for their CCA programs. Such financing can provide cost reductions approaching 20% relative to purchases from privately owned renewable projects. Issuance of revenue bonds will require a demonstration that the CCA program has a broad and stable base of customers that will provide revenues for repayment of the bonds; that it has an enforceable means of recovering potentially stranded costs from customers that leave the program; or that the CCA has another credible means of repaying the bonds. Electricity and gas prepayments are other available financing mechanisms that can lower renewable procurement costs for CCAs. As CCA programs are developed, planners should work closely with the municipalities' bankers, bond and tax counsel to ensure the program implementation plan provides appropriate credit for future debt issuances.

APPENDIX

Table A.1: Energy Commission Strategic Value Analysis Estimates of New Renewable Resources in California

Utility	Renewable	Location	MW	2010 Impact Ratio	2010 LCOE (cents/kWh)	2010 Market Price Referent (cents/kWh)	2017 Impact Ratio	2017 LCOE (cents/kWh)	2017 CPUC CC (cents/kWh)
State wide	Biomass Dairy	Diary Manure	38	-4.5	3.76	6.05	-4.5	2.14	9.15
PG&E	Biomass Forestry	RDGE CBN	59	-3	6.49	6.05	-3	5.52	9.15
PG&E	Biomass Forestry	KEKAWAKA	43	-3	7.07	6.05	-3	6.08	9.15
PG&E	Biomass Forestry	HGHLNDJ2	18	-3	10.00	6.05	-3	8.95	9.15
PG&E	Biomass Forestry	WILLITS	35	-3	7.55	6.05	-3	6.55	9.15
PG&E	Biomass Forestry	MIRABEL	18	-3	10.00	6.05	-3	8.95	9.15
PG&E	Biomass Forestry	TRINITY	26	-3	8.45	6.05	-3	7.43	9.15
PG&E	Biomass Forestry	CEDR CRK	39	-3	7.28	6.05	-3	6.29	9.15
PG&E	Biomass Forestry	TYLER	11	-3	13.21	6.05	-3	12.1	9.15
PG&E	Biomass Forestry	BIG MDWS	32	-3	7.79	6.05	-3	6.79	9.15
PG&E	Biomass Forestry	GRSS VLY	40	-3	7.22	6.05	-3	6.23	9.15
PG&E	Biomass Forestry	CH.STNJT	21	-3	9.28	6.05	-3	8.24	9.15
PG&E	Biomass Forestry	JONESFRK	25	-3	8.59	6.05	-3	7.57	9.15
PG&E	Biomass Forestry	PARADISE	26	-3	8.45	6.05	-3	7.43	9.15
State wide	Biomass Landfill Gas	Landfill Gas	318	-4.5	3.23	6.05	-4.5	2.98	9.15
State wide	Biomass WWT	Wastewater Treatment	59	-4.5	4.19	6.05	-4.5	3.79	9.15
State wide	Biomass Urban fuels	Urban Fuel	497	N/A	N/A	6.05	-4.5	6.02	9.15
Imperial	CSP Solar	Imperial	66	-3.2	6.00	6.05	-3.2	6	9.15
PG&E	CSP Solar	Plumas	0	-3	6.00	6.05	-3	6	9.15
SCE	CSP Solar	Riverside	599	-3.2	6.00	6.05	-3.2	6	9.15
SCE	CSP Solar	San Bernardino	447	-1.7	6.00	6.05	-1.7	6	9.15
SDG&E	CSP Solar	San Diego	35	-1.8	6.00	6.05	-1.8	6	9.15
Imperial	Geothermal	Superstition Mountain	10	-15.83	6.48	6.05	-15.83	5.32	9.15

Imperial	Geothermal	East Mesa	75	-5.6	10.11	6.05	-5.6	8.36	9.15
Imperial	Geothermal	Heber	42	-4.55	5.53	6.05	-4.55	4.53	9.15
Imperial	Geothermal	Mount Signal	19	-4.5	5.60	6.05	-4.5	4.59	9.15
Imperial	Geothermal	Brawley North	135	-4.42	6.13	6.05	-4.42	5.51	9.15
Imperial	Geothermal	Brawley East	129	-4.42	9.32	6.05	-4.42	8.47	9.15
Imperial	Geothermal	Brawley Mesquite	62	-4.42	10.17	6.05	-4.42	9.25	9.15
Imperial	Geothermal	Dunes	11	-4.2	8.12	6.05	-4.2	6.7	9.15
Imperial	Geothermal	Niland	76	-3.97	7.38	6.05	-3.97	6.67	9.15
Imperial	Geothermal	Glamis	6	-1.02	9.76	6.05	-1.02	8.07	9.15
Imperial	Geothermal	Salton Sea	1400	-0.6	5.34	6.05	-0.6	4.78	9.15
PacifiCorp	Geothermal	Lake City/Surprise Valley Modoc County	37	-1.05	7.17	6.05	-1.05	6.48	9.15
PacifiCorp	Geothermal	Medicine Lake Telephone Flat	175	-0.48	5.39	6.05	-0.48	4.82	9.15
PacifiCorp	Geothermal	Medicine Lake Fourmile Hill	36	-0.48	6.21	6.05	-0.48	5.58	9.15
PacifiCorp	Geothermal	Honey Lake	2	0.375	5.49	6.05	0.375	4.49	9.15
PG&E	Geothermal	Sulfur Bank Field	43	-2.91	5.54	6.05	-2.91	4.96	9.15
PG&E	Geothermal	Geysers Sonoma & Lake County	400	-2.23	8.14	6.05	-2.23	7.74	9.15
PG&E	Geothermal	Calistoga Napa County	25	-1	7.86	6.05	-1	7.28	9.15
SCE	Geothermal	Long Valley Mono County	71	0.64	4.43	6.05	0.64	4	9.15
SCE	Geothermal	Coso Hot Spring Inyo County	55	5.17	7.70	6.05	5.17	6.97	9.15
SCE	Geothermal	Randsburg	48	5.35	6.08	6.05	5.35	5.47	9.15
PG&E	High Wind	Solano County	275	-0.67	3.38	6.05	-0.67	2.45	9.15
PG&E	High Wind	Alameda County	132	-0.125	3.38	6.05	-0.125	2.45	9.15
SCE	High Wind	San Bernardino County	168	-5.3	3.38	6.05	-5.3	2.45	9.15
SCE	High Wind	Riverside County	1416	-1.4	3.38	6.05	-1.4	2.45	9.15
SCE	High Wind	Tehachapi	1200	0.008	3.38	6.05	0.008	2.45	9.15
SDG&E	High Wind	San Diego	150	-1.6	3.38	6.05	-1.6	2.45	9.15
PG&E	Low Wind	CRAGVIEW	40	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	FLTN JT2	3	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	VACA-DXN	60	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	TRAVISJT	50	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	MAINE-PR	50	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	WINDMSTR	28	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	MOORPARK	50	-0.3	7.32	6.05	-0.3	4.02	9.15
State wide	Resid. Solar	Distributed	500	-2	16.76	11.9	-2	16.76	11.9
			9,431						

(Sources: LCOE & MW values from California Energy Commission; MPR from CPUC)

Source: *Strategic Value Analysis for Integrating Renewable Energy Technologies in Meeting Target Renewable Penetration; In Support of the 2005 Integrated Energy Policy Report; Davis Power Consultants, June 2005. Costs are in 2005 dollars.*

Table A.2: Incremental Geothermal Resources

Geothermal Resource Area	County	MLK MW	Existing Gross MW	MLK-Existing MW
Brawley (North, East South)	Imperial	326	0	326
Dunes	Imperial	11	0	11
East Mesa	Imperial	148	73.2	74.8
Glamis	Imperial	6.4	0	6.4
Heber	Imperial	142	100	42
Mount Signal	Imperial	19	0	19
Niland	Imperial	76	0	76
Salton Sea (including Westmoreland)	Imperial	1750	350	1400
Superstition Mountain	Imperial	9.5	0	9.5
	Imperial Total:	2487.9	523.2	1964.7
Coso Hot Springs	Inyo	355	300	55
Sulfur Bank Field, Clear Lake Area	Lake	43	0	43
Geysers [Lake & Sonoma Counties]	Sonoma	1400	1000	400
Calistoga	Napa	25	0	25
	The Geysers Total:	1468	1000	468
Honey Lake (Wendel-Amedee)	Lassen	8.3	6.4	1.9
Lake City/ Surprise Valley	Modoc	37	0	37
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	111	40	71
Randsburg	San Bernardino/ Kern	48	0	48
Medicine Lake – Fieldwide	Siskiyou	304	0	304
Sespe Hot Springs	Ventura	5.3	0	5.3
Total: Source: California Energy Commission Geothermal Resource Staff Paper		**4825**	**1870**	**2955**

Table A.3: 2010 Levelized Cost of Geothermal Resources, Including Transmission Facilities

Geothermal Resource	Trans. Costs Million$	Trans. Impact Ratio	2010 LCOE w/PTC & Trans. Costs (cents/kWh)
Salton Sea	$233	-0.6	5.70
Dunes	$4	-4.2	8.88
Glamis	$16	-1.02	14.93
Superstition Mountain	$1.9	-15.83	6.89
Heber	$4	-4.55	5.72
Niland	$4	-3.97	7.50
Mount Signal	$8	-4.5	6.47
Long Valley Mono County	$33.4	0.64	4.37
Coso Hot Spring Inyo County	$53.1	5.17	7.85
Randsburg	$9.1	5.35	6.49
Brawley	$59.5	-4.42	9.17
Medicine Lake Siskiyou County	$170	-0.48	7.49
Geysers Sonoma County	$53.2	-2.23	8.16
Lake County Geysers and Sulfur Bank Field	$55.9	-2.91	5.74
Calistoga Napa County	$3.8	-1	8.19
Honey Lake	$3.8	0.375	9.84
Lake City/Surprise Valley Modoc County	$4	-1.05	7.41
East Mesa	$4	-5.6	10.22
Total	$679.5		

Source: California Energy Commission Consultant Report written by Davis Power Consultant under contract 500-00-031.

Table A.4: Potential Biomass Generation By County In 2010 From Landfill Gas, Dairy, and Wastewater

NAME	Dairy MWe	WWTP MWe	LFGTE NET MWe	Gross MWe	Existing MW	Economical Potential
ALAMEDA	0.05	5.32	29.89	35.26	8.22	27.04
BUTTE	0.06	0.40	1.12	1.59	0.00	1.59
CONTRA COSTA	0.15	2.59	10.88	13.62	3.00	10.62
EL DORADO	0.00	0.22	-0.15	0.07	0.00	0.07
GLENN	0.11	0.00	0.00	0.11	0.00	0.11
IMPERIAL	0.00	0.36	1.35	1.72	0.00	1.72

KERN	3.45	1.69	9.70	14.84	0.28	14.56
LOS ANGELES	0.00	29.48	116.08	145.56	121.10	24.46
MARIN	0.81	0.70	3.11	4.62	0.00	4.62
NEVADA	0.00	0.13	0.47	0.61	0.00	0.61
ORANGE	0.00	9.92	58.37	68.29	34.98	33.31
PLACER	0.08	0.45	3.03	3.56	1.00	2.56
RIVERSIDE	8.81	4.34	16.83	29.98	1.67	28.31
SAN BENITO	0.08	0.07	0.69	0.84	0.00	0.84
SAN BERNARDINO	16.15	3.90	10.96	31.01	0.00	31.01
SAN DIEGO	0.61	8.11	28.24	36.96	16.10	20.86
SAN FRANCISCO	0.00	2.98	0.00	2.98	0.51	2.47
SAN JOAQUIN	2.05	1.51	7.36	10.91	0.80	10.11
SAN LUIS OBISPO	0.00	0.45	4.45	4.90	0.00	4.90
SAN MATEO	0.00	2.02	4.96	6.98	1.90	5.08
SANTA BARBARA	0.03	0.52	1.63	2.18	0.00	2.18
SANTA CLARA	0.00	7.68	6.24	13.92	9.23	4.69
SOLANO	0.00	0.56	0.00	0.56	0.00	0.56
STANISLAUS	0.73	0.00	0.00	0.73	0.00	0.73
TULARE	5.65	0.00	0.79	6.44	0.00	6.44
VENTURA	0.00	2.03	7.72	9.75	3.30	6.45
YUBA	0.16	0.12	1.52	1.80	0.00	1.80
	38.98	85.56	325.25	449.79	202.09	247.71

Source*: Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report, CEC-500-2005-109-SD, June 2005*

Figure A.1: Existing Geothermal Resources

Source*: Energy Commission*

Table A.5: Existing California Geothermal Resources

Table 1 Location of California Geothermal Power Plants and Capacity

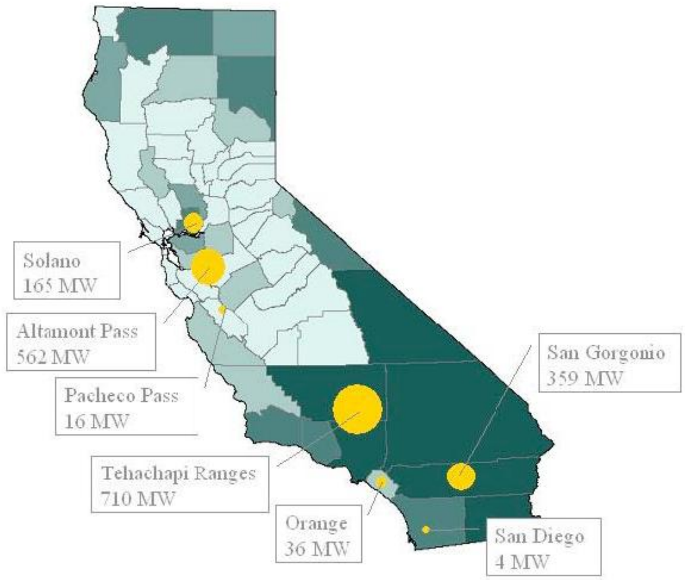
Geothermal Resource Area	County	Existing Gross MW
East Mesa	Imperial	73.2
Heber	Imperial	100
Salton Sea (including Westmoreland)	Imperial	350
	Imperial Total:	523.2
Coso Hot Springs	Inyo	300
Geysers (Lake & Sonoma Counties)	Sonoma/Lake	1000
	The Geysers Total:	1000
Honey Lake (Wendel-Amedee)	Lassen	6.4
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	40
Total:		**1870**

Source: "*New Geothermal Site Identification and Quantification*" by GeothermEx Corporation

Source*: Energy Commission*

Figure A.2: Existing Wind Resources

Figure 1. Existing wind resource areas in California



Source: California Energy Commission 2003 Wind Performance Reporting System

Table A.6: Existing California Wind Resources

Table 1. Wind Energy Resources Statistics

Resource Site	Capacity (MW)	Generation (GWh)	Number of Turbines	Location
Altamont	576	1,071	4,788	Northern CA
Solano	165	102	700	Northern CA
Pacheco Pass	16	25	167	Central CA
Tehachapi Ranges	710	1,482	3,444	Southern CA
San Gorgonio Pass	413	893	2,556	Southern CA
State Total	1,880	3,573	11,655	

Source: 2003 Wind Performance Reporting System data.

Source: *Strategic Value Analysis - Economics of Wind Energy in California, Draft Staff Paper CEC 500-2005-107-SD, June 2005*

Table A.7: Renewable Resource Eligibility for Meeting the California RPS

Table 1: Renewables Portfolio Standard Eligibility Requirements for Renewable Electricity Facilities

Resource Used	RPS Eligibility	RPS and SEP Eligibility
Biomass	Yes~~, if facility was originally on-line prior to January 1 2002.~~ ~~Facilities originally operational AFTER January 1, 2002 must meet SEP requirements.~~	Yes, if New or Repowered AND IF meets fuel use specifications, see notes below [1,2,3]
Biodiesel	Yes, subject to RESTRICTION [4]	Yes, if New or Repowered
Digester Gas	Yes	Yes, if New or Repowered
Fuel Cells	Yes, if a renewable fuel is used.	Yes, if New or Repowered
Geothermal	Yes, RESTRICTED to adjusting the baseline if the facility was originally operating prior to September 26, 1996.	Yes, if New or Repowered
Incremental Geothermal	Yes, regardless of original operation date, if certified as Incremental Geothermal Generation.[5]	Yes, if New or Repowered
Hydroelectric	Yes, RESTRICTED to facilities 30 MW or less. RESTRICTED if it was owned by an IOU as of September 12, 2002, or if the generation was procured by an IOU as of September 12, 2002, then the generation may only be counted towards adjusting an IOUs RPS baseline. Facilities originally operational AFTER September 12, 2002 must meet SEP requirements.	Yes, if 30 MW or less, New or Repowered AND IF it does NOT require a new or increased appropriation or diversion of water.
Landfill Gas	Yes	Yes, if New or Repowered
MSW Combustion	Yes, but generation from MSW combustion is RESTRICTED to adjusting the baseline AND is only eligible IF the electric generation facility is located wholly within Stanislaus County and began operating before September 26, 1996.	Combusted MSW is NOT SEP eligible.
MSW Conversion	Yes, if it meets SEP requirements.	Yes, if New or Repowered AND IF it meets the definition "solid waste conversion." [6]
Photovoltaic	Yes [7]	Yes, if New or Repowered
Solar Thermal	Yes	Yes, if New or Repowered
Tidal Current	Yes	Yes, if New or Repowered
Ocean Wave	Yes	Yes, if New or Repowered
Ocean Thermal	Yes	Yes, if New or Repowered
Wind	Yes	Yes, if New or Repowered

Notes to Table 1

[1] **New:** Resources that first begin commercial operation or are repowered on or after January 1, 2002, and meet the other eligibility requirements of Public Resources Code Section 25747, including subdivision (f), are ~~Public Utilities Code 383.5(d) are considered "new" and thus~~ eligible for SEPs.

[2] **Repowered:** Repowered generators will be eligible for SEPs if they replace their prime generating equipment and use tax records, or an acceptable alternative, to demonstrate that they have made capital investments in the facility equal to "at least 80 percent of the value of the repowered facility," as required by Public Resources Code Section 25743(c). ~~Public Utilities Code 383.5.~~ For generators with existing long-term contracts originally entered into before September 26, 1996, only generation above and beyond what is already under contract, as determined in accordance with Public Utilities Code Section 399.6 (c)(1)(C), may compete to satisfy the RPS obligation of an IOU and be eligible for SEPs.

[3] **New or Repowered Biomass:** New or repowered biomass facilities must certify to the satisfaction of the Energy Commission that fuel utilization is limited to the following pursuant to ~~Public Utilities Code 383.5(d)(6) and~~ Public Resources Code Section 25743(f):
(A) Agricultural crops and agricultural wastes and residues.
(B) Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.
(C) Wood and wood wastes that meet all of the following requirements:
(i) Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Ch. 8 commencing with Sec. 4511), Pt. 2, Div. 4, Public Resources Code).
(ii) Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.
(iii) Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by those agencies.

[4] **Biodiesel:** Electricity produced from biodiesel is eligible for the RPS IF the biodiesel is derived either from 1) a biomass feedstock such as "agricultural crops and agricultural wastes and residues" or as a result of an eligible "solid waste conversion" process (see Municipal Solid Waste Conversion) and 2) if it meets the requirements for hybrid technologies, as appropriate. Electricity generated from biodiesel derived from biomass fuel or as a result of a solid waste conversion process may also quality for SEPs if the SEP requirements for biomass or solid waste conversion are satisfied.

[5] **Incremental Geothermal:** Incremental Geothermal Generation is defined as resulting from eligible capital expenditures that reflect:
1) a substantial capital project, resulting in replacement of generating equipment or increase in steam converted to generation at a facility;
2) a sustainable impact on the underlying reservoir use; that is, a project does not cause an increase in the decline rate of the reservoir; and
3) a capital project completion date after September 26, 1996
4) AND IF the incremental output was not sold to an IOU under contract entered into prior to September 26, 1996.

[6] **Municipal Solid Waste Conversion:** A technology using a noncombustion thermal process to convert solid waste to a clean burning fuel for the purpose of generating electricity that meets all of the following criteria:
(i)The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.
(ii) The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code.
(iii) The technology produces no discharges to surface or groundwaters of the state.
(iv) The technology produces no hazardous wastes.
(v) To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream prior to the conversion process and the owner or operator of the facility certifies that the those materials will be recycled or composted.
(vi) The facility at which the technology is used is in compliance with all applicable laws, regulations, and ordinances.
(vii) The technology meets any other conditions established by the State Energy Resources Conservation and Development Commission.
(viii) The facility certifies that any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling and composting. To qualify for SEPs, the facility must certify that any local agency sending solid waste to the facility is in compliance with Division 30 of the Public Resources Code (commencing with Section 40000), and has reduced, recycled, or composted solid waste to the maximum extent feasible, and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.

[7] **Photovoltaic**: The CPUC is currently deliberating how to implement the RPS eligibility of distributed generation, particularly solar.~~, and the CEC-CPUC collaborative staff are reviewing it.~~

Source: *Draft California Energy Commission Renewables Portfolio Standard Eligibility Guidebook, November 2005*

Table A.8: Levelized Cost Assumptions For Privately Financed Vs. Publicly Financed Renewable Resources

	Merchant Wind With PTC	Merchant Wind Without PTC	Public Wind Without REPI
Input Assumptions			
Capital Cost	1250	1250	1250
MW	50	50	50
Availability	100%	100%	100%
Load Factor	30%	30%	30%
Annual Production	131,400	131,400	131,400
Heat Rate	-	-	-
Property Tax	1.1%	1.1%	1.1%
Fixed O&M ($/KW)	0	0	0
Variable O&M ($/MWH)	10	10	10
O&M Escalation	2.5%	2.5%	2.5%
Capital Structure			
Debt	0.4	0.7	1
Equity	0.6	0.3	0
Cost Of Debt	8.0%	8.0%	5.5%
Cost Of Equity (pre-tax)	25.6%	25.3%	
WACC (Pre-Tax)	18.6%	13.2%	5.5%
Composite Tax Rate	40.8%	40.8%	0.0%
After Tax Equity Return	15.2%	15.0%	0.0%
WACC (After Tax)	12.3%	10.1%	5.5%
PTC ($/MWh)	$ 18.00	$ -	$ -
Tax Depreciation (Years)	5	5	
Financing			
Interest	8.0%	8.0%	5.5%
Term	20	20	30
Debt Coverage (X Opex.)	1	1	1
Bond Insurance (X Par)	2%	2%	2%
Bond Transaction (X Par)	1%	1%	1%
Debt Service Reserve (X Par)	10%	10%	10%

Merchant Geothermal
With PTC

Input Assumptions	
Capital Cost	3700
MW	50
Availability	100%
Load Factor	93%
Annual Production	407,340
Heat Rate	-
Property Tax	1.1%
Fixed O&M ($/KW)	0
Variable O&M ($/MWH)	10
O&M Escalation	2.5%
Degradation	4.0%
Royalty	4%
Capital Structure	
Debt	0.4
Equity	0.6
Cost Of Debt	8.0%
Cost Of Equity (pre-tax)	24.5%
WACC (Pre-Tax)	17.9%
Composite Tax Rate	40.8%
After Tax Equity Return	14.5%
WACC (After Tax)	11.9%
PTC ($/MWh)	$ 18.00
Tax Depreciation (Years)	5
Financing	
Interest	8.0%
Term	20
Debt Coverage (X Opex.)	1
Bond Insurance (X Par)	2%
Bond Transaction (X Par)	1%
Debt Service Reserve (X Par)	10%

Merchant Geothermal
Without PTC

Input Assumptions	
Capital Cost	3700
MW	50
Availability	100%
Load Factor	93%
Annual Production	407,340
Heat Rate	-
Property Tax	1.1%
Fixed O&M ($/KW)	0
Variable O&M ($/MWH)	10
O&M Escalation	2.5%
Degradation	4.0%
Royalty	3%
Capital Structure	
Debt	0.6
Equity	0.4
Cost Of Debt	8.0%
Cost Of Equity (pre-tax)	25.3%
WACC (Pre-Tax)	14.9%
Composite Tax Rate	40.8%
After Tax Equity Return	15.0%
WACC (After Tax)	10.8%
PTC ($/MWh)	$ -
Tax Depreciation (Years)	5
Financing	
Interest	8.0%
Term	20
Debt Coverage (X Opex.)	1
Bond Insurance (X Par)	2%
Bond Transaction (X Par)	1%
Debt Service Reserve (X Par)	10%

Public Geothermal
Without REPI

Input Assumptions	
Capital Cost	3700
MW	50
Availability	100%
Load Factor	93%
Annual Production	407,340
Heat Rate	-
Property Tax	1.1%
Fixed O&M ($/KW)	0
Variable O&M ($/MWH)	10
O&M Escalation	2.5%
Degradation	4.0%
Royalty	4%
Capital Structure	
Debt	1
Equity	0
Cost Of Debt	5.5%
Cost Of Equity (pre-tax)	
WACC (Pre-Tax)	5.5%
Composite Tax Rate	0.0%
After Tax Equity Return	0.0%
WACC (After Tax)	5.5%
PTC ($/MWh)	$ -
Depreciation (Years)	
Tax Depreciation (Years)	
Financing	
Interest	5.5%
Term	30
Debt Coverage (X Opex.)	1
Bond Insurance (X Par)	2%
Bond Transaction (X Par)	1%
Debt Service Reserve (X Par)	10%

Public Wind
With REPI

Input Assumptions	
Capital Cost	1250
MW	50
Availability	100%
Load Factor	30%
Annual Production	131,400
Heat Rate	-
Property Tax	1.1%
Fixed O&M ($/KW)	0
Variable O&M ($/MWH)	10
O&M Escalation	2.5%
Capital Structure	
Debt	1
Equity	0
Cost Of Debt	5.5%
Cost Of Equity (pre-tax)	
WACC (Pre-Tax)	5.5%
Composite Tax Rate	0.0%
After Tax Equity Return	0.0%
WACC (After Tax)	5.5%
REPI ($/MWh)	$ 18.00
Depreciation (Years)	
Tax Depreciation (Years)	
Financing	
Interest	5.5%
Term	30
Debt Coverage (X Opex.)	1
Bond Insurance (X Par)	2%
Bond Transaction (X Par)	1%
Debt Service Reserve (X Par)	10%

Public Geothermal
With REPI

Input Assumptions	
Capital Cost	3700
MW	50
Availability	100%
Load Factor	93%
Annual Production	407,340
Heat Rate	-
Property Tax	1.1%
Fixed O&M ($/KW)	0
Variable O&M ($/MWH)	10
O&M Escalation	2.5%
Degradation	4.0%
Royalty	4%
Capital Structure	
Debt	1
Equity	0
Cost Of Debt	5.5%
Cost Of Equity (pre-tax)	
WACC (Pre-Tax)	5.5%
Composite Tax Rate	0.0%
After Tax Equity Return	0.0%
WACC (After Tax)	5.5%
REPI ($/MWh)	$ 18.00
Depreciation (Years)	
Tax Depreciation (Years)	
Financing	
Interest	5.5%
Term	30
Debt Coverage (X Opex.)	1
Bond Insurance (X Par)	2%
Bond Transaction (X Par)	1%
Debt Service Reserve (X Par)	10%

GLOSSARY

CCA	Community Choice Aggregators
CPCN	Certificate of Public Convenience & Necessity
CFR	Code of Federal Regulations
ESP	Energy Service Providers
GWh	Gigawatt hours
IEPR	Integrated Energy Policy Report
LCOE	Levelized Cost of Energy
LP	Low Pressure (?)
NCI	Navigant Consulting, Inc.
PG&E	Pacific Gas & Electric
PTC	Production Tax Credit
RPS	Renewable Portfolio Standard
RRDR	Renewable Resources Development Report
SCE	Southern California Electric
SDG&E	San Diego Gas & Electric
Solar PV	Solar Photovoltaic
SVA	Strategic Value Analysis